Quarterly Report: April - June 2011 (Q2/11)

August 18, 2011

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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.

Table of Contents

List of Tables and Figures

Executive Summary

General Market Outcomes

The average pool price in Q2/11 was $51.90/MWh, higher than anticipated and due, in part, to the prolonged outage at Sundance units #1 & #2 and the delayed commissioning of Keephills #3. Pool price volatility in terms of coefficient of variation continues to be high and the spread between average on- and off-peak pool prices was almost 4:1, higher than normal. Natural gas prices trended up slightly in the $3 - $4/GJ range. The average market heat rate was 14 GJ/MWh (On-Pk: 20 GJ/MWh, Off-Pk: 6 GJ/MWh).

System supply in terms of Maximum Capability increased due to the addition of Keephills #3 – although it did not generate very much in the quarter since it is still in the commissioning phase. Hence the capacity factor for coal generation dipped from Q2/11 even though total production in GWh was about the same. The average production from the fleet of wind farms was 30% in Q2/11, up over Q1/11(26%) and Q2/10(25%).

Pool prices in Alberta throughout the quarter were sufficiently higher than those in neighbouring markets to attract significant volumes of imports, particularly on the BC intertie.

Monitoring Indices

The supply cushion – pool price relationship was again used to screen hourly market outcomes for the quarter. A total of 53 high outliers were identified for Q2/11, more than would be expected based on the historical data used to establish the baseline parameters. This is a similar situation as occurred in the last three quarters.

The report uses the output gap analysis to assess the 53 hours identified as statistical outliers using the MSA's baseline relationship between the supply cushion and pool price. The assessment is simply a factual report of events of interest and part of the MSA's public reporting responsibility. We do not reach any conclusion at this time that they are the result of inappropriate conduct or market design flaws.

The data for the past twelve months on statistical outliers clearly demonstrates a shift in behaviour for supply cushions in the range of 500 MW through 1000 MW and will require further analysis.

The market observed several low prices events this quarter, including a total of 6 hours of $0/MWh pool prices. The MSA examined the use of OPP 103 in hours of supply surplus. We are of the view that a rule amendment to allow negative price offers would be the economically efficient solution to situations of supply surplus.

The MSA observed the curtailment of output at a wind farm which was not due to transmission issues. Upon receiving the data from the participant, it was high speed cut out that caused the curtailment. The event caused us to think about the possibility of withholding of wind output. The rules regarding the integration of wind into the system are in development by the AESO. During this transitional period, the MSA would consider any examples of such behaviour to be a serious matter.

The report presents some metrics on the merit order, including measures on how close the market was to supply surplus and supply shortfall conditions.

Retail Market

New Energy Price Setting Plans for the RRO through the period 2011-14 are now in play, although for ENMAX it is only an interim arrangement. In the case of EPCOR, having spun off their generation assets to Capital Power, their EPSP is a procurement plan, primarily through a series of auctions. The auctions for July ran into some difficulties in terms of attracting sellers. The MSA will continue to watch the RRO as it unfolds.

The MSA is conducting a number of Code of Conduct audits this summer as part of its legislated responsibilities. This year, four wires owners will be subject to audit.

Forward Market

Trading volumes remain modest, and less than they were a year ago. In looking at types of traders it appears that the market shares of banks and funds (market speculators) is down considerably from last year. Banks and funds are an important part of the forward market as they provide market liquidity. There appears to be an increasing perception of risk in Alberta's spot market that flows through into the forward market. The short-term swings in forward prices are greater than before and this can cause problems to traders that find themselves 'stopped out' and forced to stay on the sidelines.

An assessment of the evolution of the April contract revealed that most of the price movements coincided with market news as is expected. However, whilst the price of the April contract swung significantly over its main trading period, the forward prices were well above the actual settled price.

Compliance Update

The MSA compliance team has observed that market participants in Q2/11 were less prompt in their self-reporting of potential breaches. Participants need to remember that the benefits of self reports are lost to the participant if the AESO and/or MSA identify them first.

On the mandatory reliability standards front, we recommend that registered entities pay closer attention to compliance with the requirements of one of the event-based standards, CIP-001-AB-1 (sabotage reporting).

1 General Comments on Market Outcomes

Sundance #1 & #2 units remained offline throughout Q2/11 and the commissioning of Keephills #3 was delayed. Both were factors contributing to the average pool price of $51.90/MWh for Q2/11. This average price is substantially lower than Q1/11 ($82.05/MWh) and Q2/10 ($81.15/MWh) as shown in Table A.1. The pool price duration curve for Q2/11 shows that 6% were of pool prices were above $100/MWh (See Figure A.1). It is the proportion of high price hours in a quarter that tends to drive the average price, rather than effects across all hours. In Q2/11 this proportion was less than for Q1/11 or Q2/10. The volatility of pool prices, whether measured by standard deviation or coefficient of variation, continued to be high in Q2/11 (See Table A.1).

AECO-C natural gas prices were again very stable throughout the quarter in the range $3 to $4/GJ – a band of prices that have persisted for more than a year (See Figure A.2). The quarterly market heat rate was 14 GJ/MWh (On-Peak: 20 GJ/MWh, Off-Peak: 6 GJ/MWh). These market heat rates are substantially lower than in Q1/11. In part, this was a function of the less tight market in Q2/11 vs. Q1/11. Comparing

Figure 2.1 for Q1/11 with that for Q2/11 (see below), we see that in Q1/11 some 44% of all the hours were in the supply cushion range less than 1000 MW and only 23% in the current quarter.

System capacity (Maximum Capability) increased significantly with the addition of Keephills #3, although the plant is still in its commissioning phase and not at full production as of the end of July. Plant availability in Q2/11 was lower than Q1/11 with average available capacity of 8,512 MW vs. 9,047 MW, due to increased planned plant maintenance of the gas-fired generators (See Table B.1). Fleet generation was also down quarter over quarter due to lighter spring loads. Net imports continued at high levels in Q2/11 at some 875 GWh, down slightly from Q1/11 (1,034 GWh).

Utilization of the interties for imports was high in Q2/11 as shown in Figure D.1. As noted above, Alberta imported 875 GWh on a net basis, equivalent to an average of about 400 MW. The driver for these imports is easy to see in Figures D.2 wherein it is evident that Alberta pool prices continue to be markedly higher than those in neighbouring markets, especially during on-peak hours. The general price outlook for many electricity markets in our region, including Mid C, in the near to mid term is that they will be relatively 'soft' and generally lower than Alberta.

2 Monitoring Indices

Monitoring indices are simply data summaries the MSA uses to flag apparent anomalous market outcomes or report on the competitive health of the market for further assessment now, or in the future.

The new metrics we examine this quarter relate to the energy market merit order and various aspects of it. These are all inter-related and examine the following attributes:

- Frequency of close to supply surplus conditions;
- Frequency of close to supply shortfall conditions; and,
- Merit order depth.

This analysis is described in Section 2.4.

The detailed derivation of the supply cushion for each hour was described in the MSA's Q3/10 report. Data for the period February 1, 2008 through June 30, 2010 was used to establish a statistical baseline for the relationship between the supply cushion and pool price. For a given hour, the supply cushion is the volume of energy available to the system controller but not called upon to meet load. Supply cushion measures market tightness and would be expected to be strongly related to pool price. This relationship is a prime metric to enable the MSA to identify anomalous hours. It does not speak to the possible reasons for the anomaly, but it does flag the hour as being unusual.

In the Q1/11 report, we described a detailed methodology for analysis of the undispatched MW in the merit order. This is termed an output gap analysis. In the cases where market prices are higher than the short-run costs of the generators, it is an analysis of economic withholding. To be clear, as explained in the MSA's *Offer Behaviour Enforcement Guidelines*, economic withholding by individual market participants is not proscribed under Alberta's market construct. However, identification and reporting of its occurrence contributes to stakeholders' understanding of market outcomes and also provides a record for the longer term assessment of the health of the market.

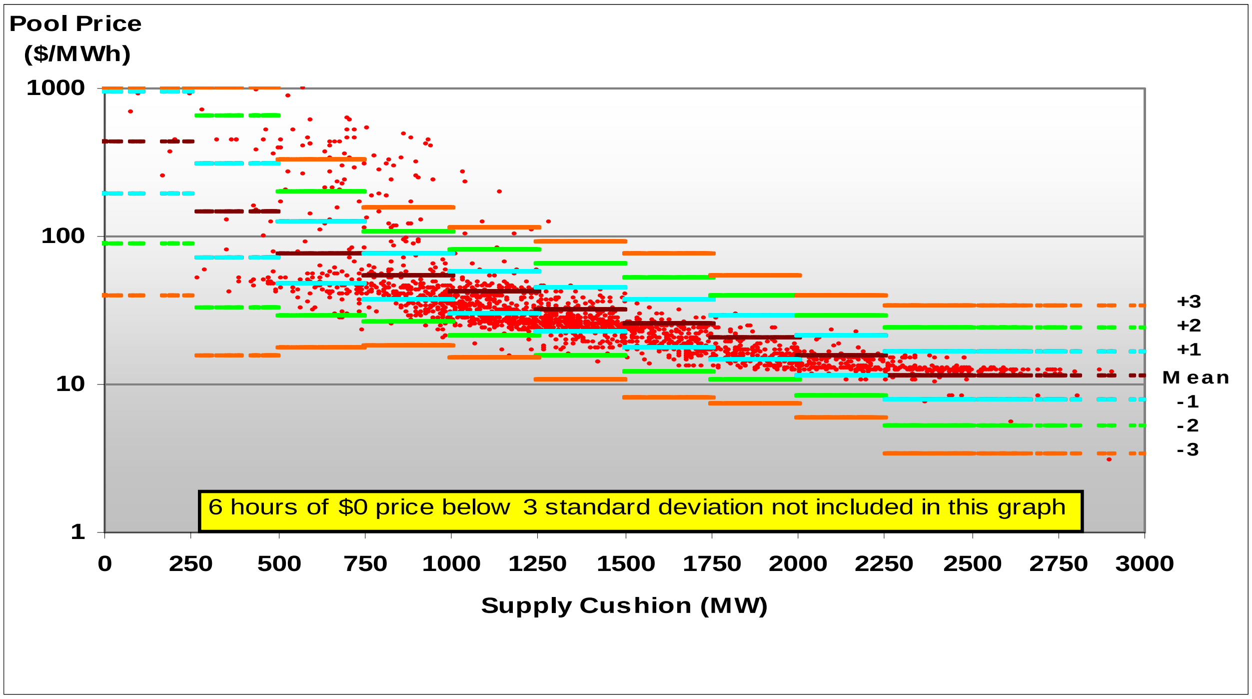
Before explaining and applying the output gap analysis to observed high-price and statistically unusual market outcomes, the next section summarizes the Q2/11 supply cushion and price data.

2.1 SUPPLY CUSHION ANALYSIS – Q2/11

The supply cushion and associated pool price data for Q2/11 are plotted in Figure 2.1. It is evident that there are a relatively large number of hours above the line representing 3 standard deviations above the mean in the supply cushion range from approximately 500 MW through about 1000 MW. In Q2/11 there were a total of 438 hours in the range 500 MW – 1000 MW of supply cushion and 48 hours (11%) were more than 3 standard deviations above the mean. If the historic data used to establish these bounds are from the normal distribution, less than 0.5% of the observations would be more than 3 standard deviations above the mean. The results are largely in line with recent quarters adding further support to the notion that there has been a shift in behaviour of market participants since the baseline was established.

In terms of pool prices that were unusually low relative to the amount of supply cushion, across the whole spectrum of supply cushion there were 7 events that were more than 3 standard deviations below the mean. There were 6 hours with $0 pool price plus one hour where SMP was at $0 for part of the hour.

Figure 2.1: Q2/11 Supply Cushion v. Pool Price (Confidence Bands Based on Historic Data)



	=<250	>250 <=500	>500 <=750	>750 <=1000	>1000 <=1250	>1250 <=1500	>1500 <=1750	>1750 <=2000	>2000 <=2250	>2250	Total
>=+3	0	0	25	23	4	1	0	0	0	0	53
<+3 & >=2	0	6	14	10	4	0	0	0	0	0	34
<+2 & >=1	14	8	10	10	5	4	2	1	5	0	59
<+1 & >=mean	9	2	6	29	57	51	32	19	22	156	383
<mean & >=-1	2	5	32	137	163	277	191	130	148	14	1099
<-1& >=-2	0	19	52	79	188	58	66	59	3	2	526
<-2& >=-3	0	0	3	8	6	4	0	0	0	1	22
<-3	0	0	0	0	0	0	0	0	0	7	7
Total	25	40	142	296	427	395	291	209	178	180	2183

2.2 OUTPUT GAP ANALYSIS – Q2/11

The output gap analysis calculates the market supply cushion by market participant, identifying the proportion of the supply cushion that is attributable to each market participant in a given hour. The theory and its application in our work were fully described in the MSA's Q1/11 report.

For the analysis of Q2/11 data on unusual high-priced hours (>3 StD), the MSA has manually adjusted the supply output gap results. For each of the 53 hours (events), the offer blocks from PPA assets, or shared assets were manually reassigned to the participant believed to have had offer control in that hour. Not all of the 53 hours were affected by this process, and not all participants' monthly average share of supply cushion changed as a result of the manual intervention.

2.2.1 Summary of Q2/11 Events

Table 2.1 breaks down the average supply cushion and pool price of >3 StD events by month. It also shows the average percentage contribution by participant to the withheld supply in these hours. Letters A through E denote the five largest participants in the market by generating asset offer control. In Q2/11, participant C was responsible for 56% percent of the withheld supply during the 53 hours when prices were >3 StD.

Table 2.1: Output Gap Analysis Summary of >3 StD Events of Q2/11

						Average Share of Supply Cushion by Participant					
Month	Count of Events	Average Price of the Events	Max Price of the Events	Min Price of the Events	Average SC of the Events	A	B	C	D	E	Other
Apr-11	42	$ 347.03	$ 625.46	$ 124.70	822	4%	12%	53%	26%	1%	4%
May-11	4	$ 406.96	$ 447.21	$ 352.65	598	29%	4%	47%	17%	0%	3%
Jun-11	7	$ 589.16	$ 985.98	$ 375.16	585	0%	5%	76%	15%	0%	4%
Q2/11	**53**	**$ 383.53**	**$ 985.98**	**$ 124.70**	**774**	**5%**	**11%**	**56%**	**24%**	**1%**	**4%**

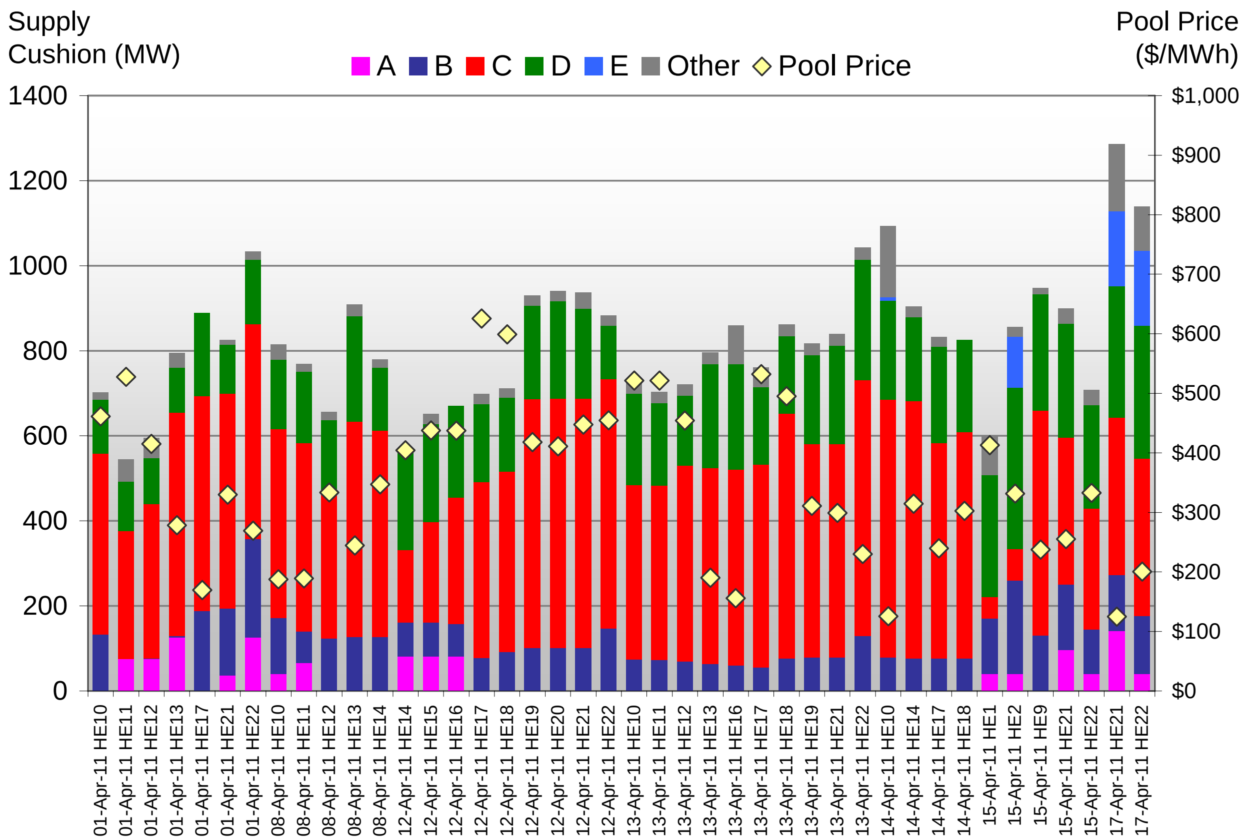
Given that there were roughly an equal number of hours in each month of Q2/11 where supply cushion was in the range 500 to 1000 MW (the supply cushion range producing the majority of the outliers) it is not clear why there is a large difference in number of outliers in each month. Table 2.1 shows that the average size of supply cushion in the hours producing the price outliers in April was substantially higher than May and June. Absent any other explanation, it appears there was a greater willingness to take dispatch risk in April in an effort to increase pool price. This willingness appears to be provided by Participant C, and to a lesser extent D and B.

The following sections describe the event analysis on a monthly basis.

2.2.1.1 April 2011

Across the 42 events (hours) that occurred in April, participant C was responsible for more than half of the economically withheld energy. Participant D averaged 26% in these hours and no other participant had a significant share. The distribution of market share by hour and associated pool price are shown in Figure 2.2. Many of the hours are grouped almost sequentially on a given day and we have described the events in terms of these groups.

Figure 2.2: Output Gap Analysis - April 2011



April 1: HE10-HE13, HE17, HE21-HE22

The pool price of HE10 almost quadrupled from HE09, rising from $120.64/MWh to $461.12/MWh. The increase was caused primarily by Participant C moving its offer prices of ~300 MW of energy from a range of $100/MWh to $350/MWh to the vicinities of $460/MWh and $630/MWh. The change in offer prices reduced the number of MW between $100/MWh and $450/MWh in the merit order. As the supply cushion dropped by 120 MW in HE10, the pool price increased.

Participant C did not encounter any competitive response from other suppliers in HE10 to HE12. Presumably this is due to the fact that by the time the market observed a price increase in HE10, the next time that offers could be changed in response was for HE13.

Participant A's offer price of 75 MW for HE11 rose from below $200/MWh to close to $900/MWh. With the supply cushion dropping by 100 MW in HE 11, the pool price increased to $527.54/MWh.

In HE12 the supply cushion increased by about 50 MW. However, since at the $450 - $600/MWh price levels the merit order was extremely thin, this small change in supply cushion was enough to drive the pool price down by $112.31 to $415.23/MWh.

The first chance to compete with the offer strategies observed in HE10 was HE13. However, wind generation picked up and caused the supply cushion to increase by about 200 MW and resulted in the pool price dropping from $415.23/MWh to $278.23/MWh.

Starting HE14, Participant A reduced the offer price of 50 MW from $240/MWh to below $70/MWh. Supply cushion increased for the next few hours and pool price settled below $75/MWh for HE14-HE16. In HE17, as the supply cushion tightened by 128 MW, pool price increased from $74.88/MWh to $169.44/MWh, >3 StD once again.

In HE21, Participant A returned to the strategy of offering at prices above $200/MWh while supply cushion dropped by 160 MW. Pool price of HE21 was significantly higher than of HE20, rising from $59.36/MWh to $329.75/MWh.

In HE22, pool price decreased by about $60.73/MWh as the supply cushion increased by 210 MW. Participants C's offers were unchanged from HE10 to HE23.

April 8: HE10-HE14

Beginning in HE08, Participant C raised the offer prices of >280 MW energy from below $50/MWh to between $200/MWh and $400/MWh. As the supply cushion varied between HE10 and HE14, pool price doubled from HE09 to HE10 and peaked in HE14 at $347.30/MWh. In HE13, Participant C further raised the offer prices of 400 MW to around $400/MWh. The offer prices of Participant C were higher in HE13-HE14 than in HE10-HE12 and served, in part, to maintain the high pool prices through this period.

April 12: HE14-HE22

Starting HE8, Participant C raised the offer prices of 380 MW from less than $50/MWh to ~$400/MWh. Price began to rise noticeably from HE10 to HE11 moving up from $47.53/MWh to $89.79/MWh. In HE17, Participant C further raised the offer prices of about 500 MW to above $550/MWh. Starting in HE14, pool prices exceeded $400/MWh and stayed above $400/MWh until HE22, the last hour that Participant C had its energy blocks priced high. Although in HE17, Participant A lowered the offer prices of about 80 MW from above $800/MWh to below $50/MWh, the pool prices from HE14 to HE22 were above $400/MWh, and >3 StD.

April 13: HE10-HE13, HE16-HE19, HE21-HE22

In HE09, Participant C raised the offer prices of close to 400 MW from below $50/MWh to above $400/MWh. In the same hour, Participant D raised the offer prices of 120 MW from $39 - $90/MWh to $299 -$650/MWh. The offer prices of Participant A and Participant C remained at similar levels HE10 through HE22, and HE10-HE13, HE16-HE19 and HE21-HE22 observed prices that were >3 StD.

April 14: HE10, HE14, HE17-HE18

HE09-HE14, Participant C raised the offer prices of more than 500 MW from below $50/MWh to above $520/MWh. The price impact in HE09 was limited by the increase in supply cushion. However, in HE10 the supply cushion reduced and the pool price of HE10 rose to $125.59/MWh.

In HE14, the supply cushion dropped from 1007 MW to 904 MW, the pool price increased to $314.78/MWh.

In HE15 and HE16, Participant C lowered the offer prices of the megawatts that were priced up in HE09 to below $50/MWh, but raised them again in HE17 and HE18. As a result, although in HE17 and HE18, the supply cushions were higher than those in HE15 and HE16, the pool prices in HE17 and HE18 were much higher.

April 15: HE01-HE02, HE09, HE21-HE22

In HE01 and HE02, Participant E increased the offer price of 120 MW from below $85/MWh to above $580/MWh. Coincidentally, the supply cushion dropped by 98 MW, from 695 MW in HE24 to 597 MW in HE01. The pool price of HE01 increased $173.06, from $239.61/MWh in HE24 to $412.67/MWh. In HE02, although the supply cushion recovered to 856 MW, more than 150 MW higher than in HE24, the pool price in HE02 was $91.91 higher than HE24.

In HE08, Participant C raised the offer prices of about 450 MW from below $50/MWh to above $500/MWh and the same offer strategy remained in HE09. HE09 pool price rose to $237.33/MWh from $103.40/MWh in HE08. In HE10, Participant C lowered the offer prices of 300 MW to below $40/MWh and pool price in HE10 fell to $59.14/MWh with almost no change in supply cushion.

Participant C's offering up strategy continued through HE23 and there was only one other notable offer change. In HE21 and HE22, Participant A priced >100 MW from below $25/MWh to over $300/MWh and the pool prices of both hours were $255.23/MWh and $332.57/MWh, respectively.

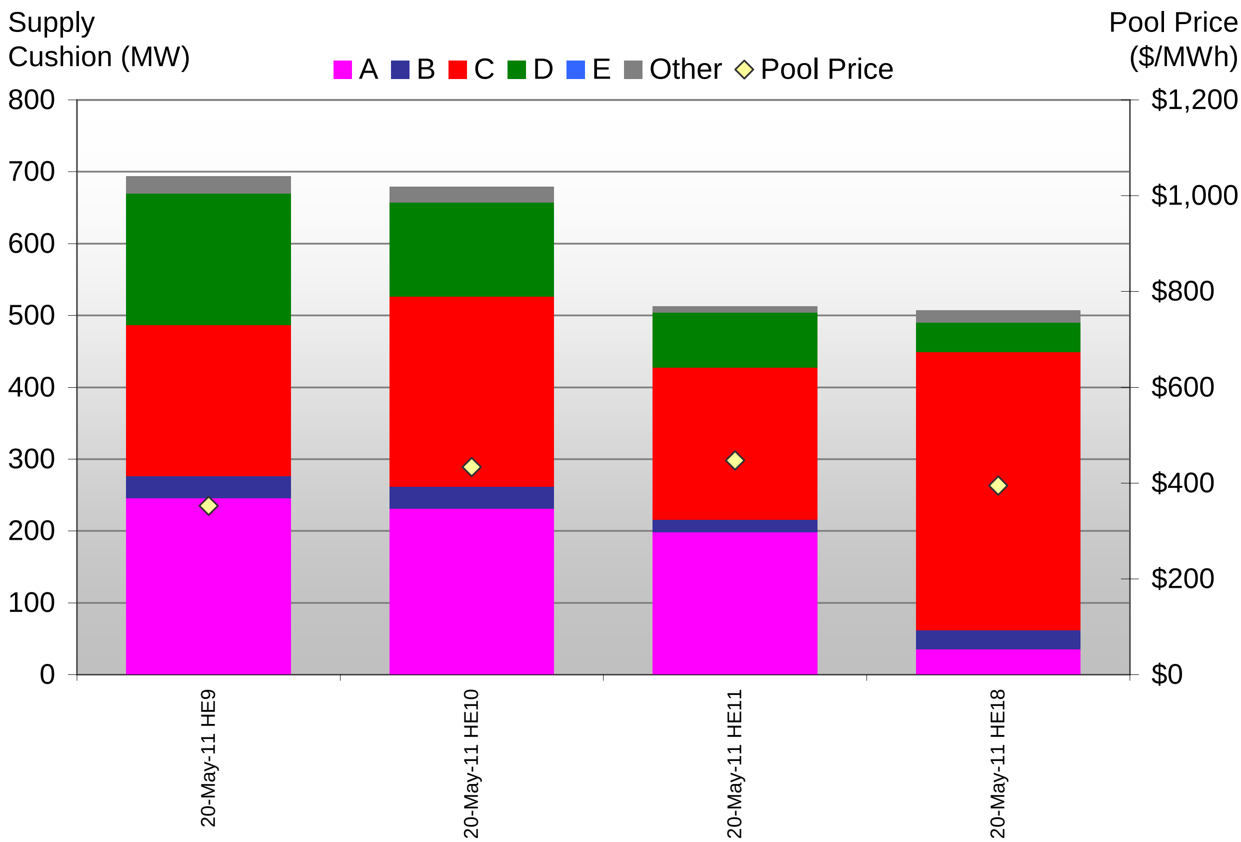
April 17: HE21-HE22

Starting HE19, Participant C raised the offer prices of ~270 MW from below $50/MWh to above $650/MWh. In HE21 and HE22, Participant C lowered the offer prices of these MW to around $300/MWh. In the same hour, a smaller generator increased its offer price of 52 MW from $41/MWh to above $200/MWh. The pool prices in HE21 and HE22 settled >3 StD, at $124.7/MWh and $200.45/MWh, respectively.

2.2.1.2 May 2011

In May 2011, there were only 4 hours when the pool prices settled >3 StD (Figure 2.3). The number of hours that Participant C priced up large amounts of energy was significantly less in May than in April.

Figure 2.3: Output Gap Analysis - May 2011



May 20: HE09-HE11, HE18

In HE08, Participant C increased the offer prices of more than 300 MW from below $50/MWh to above $450/MWh. In HE09, Participant A priced 105 MW from below $20/MWh to above $450/MWh. This coincided with a reduction of supply cushion of 390 MW, mostly due to increasing load. The pool price of HE09 was $352.65/MWh, tenfold that of HE08.

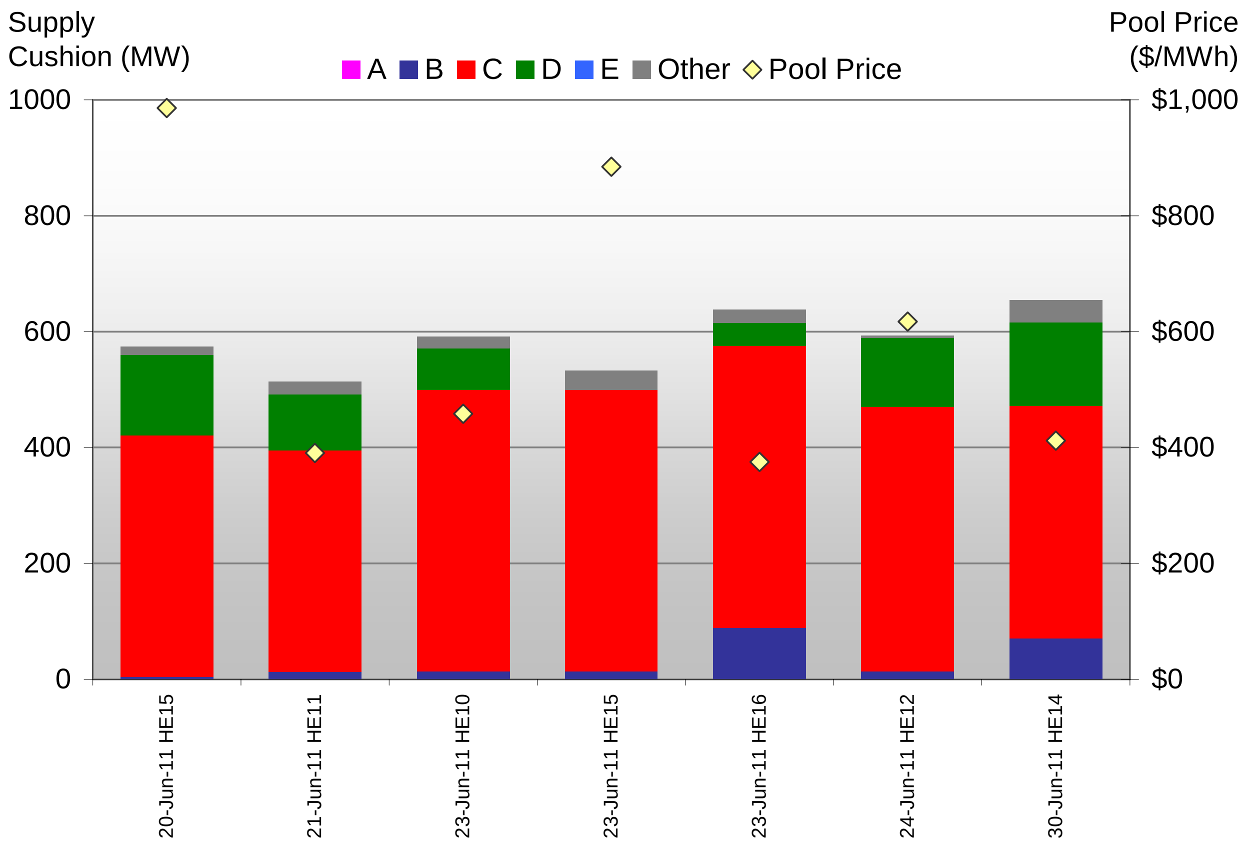
In HE10, Participant A increased the offer price of 30 MW from $450/MWh to above $700/MWh. In the same hour, Participant D moved 38 MW down from ~$990/MWh to about $400/MWh, which undercut the offers of Participant C. With supply cushion essentially unchanged, pool price rose to $433.39/MWh.

In mid afternoon Participant D moved an additional 40 MW down from ~$900/MWh to ~$300/MWh, undercutting the offers of Participant C. Otherwise, offer strategies remained essentially unchanged and pool prices remained high until HE19.

2.2.1.3 June 2011

In June, there were 7 hours when the pool prices were settled >3 StD. In all these hours, Participant C withheld 300 - 500 MW energy and accounted for 76% of the total economically withheld energy.

Figure 2.4: Output Gap Analysis - June 2011



June 20: HE15

In HE15, Participant C raised the offer prices of more than 300 MW from below $50/MWh to about $990/MWh. Although the supply cushion increased 102 MW in HE15, the pool price increased from $47.56/MWh to $985.98/MWh. Participant C's offer strategy continued to HE19, although with lower pool prices and the 300 MW were out of merit throughout.

June 21: HE11

Starting HE08, Participant C raised the offer prices of more than 450 MW from below $45/MWh to above $420/MWh. The pricing up coincided with a decrease in supply cushion in subsequent hours. In HE11, pool price rose to $390/MWh. Participant C further raised the offer prices of 480 MW to above $980/MWh HE13 through HE17.

June 23: HE10, HE15-HE16

Starting HE09, Participant C raised the offer prices of more than 480 MW from below $50/MWh to above $900/MWh. This strategy continued to HE16. In HE10 the supply cushion fell by 66 MW from HE09 and pool price doubled, rising to $458.42/MWh from $209.35/MWh.

In HE15 and HE16, Participant D lowered the offer price of 5 MW in each hour from $890/MWh to $840/MWh. In HE16, a small generator also lowered the offer price of 10 MW from $999/MWh to

$200/MWh and $500/MWh. With 533 MW and 638 MW supply cushions in HE15 and HE16 respectively, the pool prices settled at $884.71/MWh and $375.16/MWh.

June 24: HE12

HE09 through HE13, Participant C raised the offer prices of 420 MW from below $50/MWh to above $600/MWh. With the gradual tightening of supply over subsequent hours pool prices rose quickly and peaked at $617/MWh in HE12. The supply cushion in HE12 was 593 MW, 33 MW higher than in HE15 after Participant C ceased the pricing up strategy begun in HE09. However, the pool price of HE12 was much higher than that of HE15.

June 30: HE14

Between HE10 and HE14, Participant C raised the offer prices of 383 MW from below $50/MWh to between $420/MWh and $850/MWh. Pool price peaked in HE14 at $411.83/MWh. With a supply cushion of 655 MW, this price was $251.60 higher than in HE15 after Participant C ceased the pricing up strategy, although the supply cushion in HE14 was more than 200 MW higher than HE15.

2.2.1.4 Summary of >3StD Events

Q2/11 produced a larger-than-expected number of hours with pool price >3 StD from the mean based on the statistical relationship established between supply cushion and pool price. The number of hours was similar to that for Q1/11 suggesting that there has been a shift in offer behaviour in the past two or three quarters. The output analysis indicated that in the majority of these hours, economic withholding through increasing the offer prices of large volumes of energy, particularly by Participant C, was an important driver. As noted before, these comments need to be considered in the context of the fact that we had 53 hours of unusual outcomes in a quarter of more than 2000 hours.

As observed in previous quarterly reports, the findings from a single metric are not likely, when taken in isolation, to form a basis to conclude that market outcomes observed are inconsistent with the *fair, efficient and openly competitive* standard set out in section 6 of the EUA. This information forms part of the record for a longer term consideration of the competitiveness and performance of the Alberta market.

2.2.1.5 Statistical Outliers Q3/10 through Q2/11

We now have a full year of results to draw on since establishing the statistical baseline of the supply cushion pool price relationship. Table 2.2 shows the numerical results for the 12 month period July 1, 2010 through June 30, 2011. The results are still in line with those of the baseline period in that about 4% of all hours are outside the band of the mean + / - 2 standard deviations, close to the 5% that would be expected. However, a closer examination of the data shows the pattern we have commented upon in each of the four quarters comprising this period. That is, an exceptional number of outliers exists beyond >3StD in the supply cushion range 500 MW to 1000 MW, and to a lesser extent in the range 1000 MW to 1250 MW.

Table 2.2: Supply Cushion - Pool Price July 2010 through June 2011

	<=250	>250 <=500	>500 <=750	>750 <=1000	>1000 <=1250	>1250 <=1500	>1500 <=1750	>1750 <=2000	>2000 <=2250	>2250	Total
>=+3	0	0	82	80	39	13	2	1	0	0	217
<+3 & >=2	0	33	42	24	20	2	0	3	6	11	141
<+2 & >=1	27	38	55	45	30	13	9	47	73	66	403
<+1 & >=mean	36	56	70	80	166	298	434	304	183	245	1872
<mean & >=-1	6	62	235	606	1034	1120	683	377	268	66	4457
<-1& >=-2	3	56	271	451	457	144	100	101	15	17	1615
<-2& >=-3	6	0	3	12	6	4	0	2	1	3	37
<-3	0	0	0	0	0	0	0	0	0	7	7
Total	78	245	758	1298	1752	1594	1228	835	546	415	8749

2.2.1.6 Supply Surplus Events in Q2/11

During Q2/11 there were a number of events where system marginal price reached $0. Such events are of concern to the MSA as they indicate that the market may fail to clear (supply = demand) without administrative intervention from the AESO. Currently, the AESO uses the procedures set out in *OPP 103 Dispatching Multiple $0 Offers.* They are also contemplating changes to the supply surplus rules and it might be instructive to consider recent experiences in its use.

The Q2/11 $0 and supply surplus events are summarized in Table 2.3. In accordance with OPP 103, if it is anticipated that "system supply will exceed demand and consists of only $0 offers during the next scheduling hour, import interchange transactions will be denied." This requires that the system controller make an assessment as to what level of interchange schedules are to be denied, and results in the possibility that in real time SMP may be above $0 for all or part of the hour. Out of the twelve events listed in Table 2.3, imports were curtailed prior to the scheduling hour on ten occasions. In four of these SMP was above $0 for all or part of the hour. As long as the interties are not able to respond to dispatch, there will be occasions when intertie schedules are cut and in real time the price is not $0 for the full hour. It must also be recognized that the system controller is using forecast information when making the curtailments.

Table 2.3: Supply Surplus Events

Date	Hour Ending	Pool Price ($/MWh)	Max SMP ($)	Min SMP ($)	Imports (MW) curtailed under OPP 103
5/17/2011	1	12.55	12.96	11.55	200
5/17/2011	3	11.55	11.55	11.55	100
5/17/2011	4	5.58	11.55	0	100
5/17/2011	5	0	0	0	271
5/17/2011	6	7.51	11.55	0	174
5/27/2011	1	3.08	11.55	0	0
5/27/2011	2	0	0	0	150
5/27/2011	3	0	0	0	175
5/27/2011	4	0	0	0	175
5/27/2011	5	0	0	0	200
5/27/2011	6	0	0	0	100
5/27/2011	7	3.41	11.55	0	0

OPP 103 is not explicit on how import curtailments are made. The policy section of the OPP states "Import interchange transactions are deemed to be flexible blocks before the scheduling hour" and "Flexible blocks of the $0 offers will be dispatched for partial volumes on a pro rata basis". However the procedures section is less clear, stating simply "If it is anticipated that the system supply will exceed demand for the next hour and will consist of only multiple $0 blocks, the SC will deny the next hour import interchange transactions, if required". Following clarification from AESO, we understand that all intertie curtailments are on the last-in-first-out principle, and this procedure was followed in the supply surplus events in Q2/11.

If supply surplus situations warrant, OPP103 also contemplates that $0 offer blocks will be dispatched or directed down. Flexible blocks are dispatched down first on a pro-rata basis, followed by directives to units with high dispatch variance, imports and finally inflexible offer blocks. Certain units are exempt from being directed to minimum stable levels. In examining the Q2/11 events, we find no evidence of flexible offer blocks being dispatched down. In most of the events there is a significant number of $0 offers and of flexible offer blocks. For example, on May 27, 2011 HE2 there were 54 $0 offer blocks of which 30 had been declared as flexible. Given the pro-rata dispatch contemplated in OPP 103, this could pose a practical problem in that any required dispatch down is spread among a large number of offers and would require a large number of dispatches each for a small number of MW. This may make the procedure difficult for the system controller to follow, but was not found to be required in the Q2/11 events.

While not all zero dollar events would likely cause a need for dispatching down $0 offer blocks, it is likely that some would. The MSA examined the use of regulating reserves during the supply surplus events. In the absence of dispatches to $0 offer blocks, the balance between supply and demand will be maintained by moving towards the lower end of the regulating reserve range if load is falling, all else equal.

Table 2.4 shows the use of regulating reserves in each of the supply surplus events. The regulating reserve range in these supply surplus events is approximately 120 to 150MW. The position within the regulating reserve range is typically described in terms of the remaining regulation reserve down (Reg. down) and up (Reg. up). It is not uncommon for the full regulating range to be utilized in an hour as different units ramp in response to dispatch. In fact, the amount of regulating range on the system at a given time is based on an expectation of how much system ramping might occur at that time. It is more unusual for extreme points in the regulating reserve range to persist over an hour or more. A persistent low level for Reg. down might in the case of a supply surplus event indicate a problem or reluctance to enact the steps within OPP 103. Of the supply surplus events examined, the MSA found only one hour which featured an unusually low level of Reg. down (May 27, 2011, HE03). Such a low level of average Reg. down in an hour occurs only about 0.4% of the time based on data from February 2008. Overall, the data is inconclusive in terms of demonstrating a desire to avoid the steps of OPP 103.

Table 2.4: Use of Regulating Reserves in Supply Surplus Events

Date	HE	Average Reg., Down (MW) [A]	Average Reg. up (MW) [B]	[A]/ ([A]+[B])%
5/17/2011	1	55	69	44%
5/17/2011	3	37	103	26%
5/17/2011	4	14	127	10%
5/17/2011	5	86	54	61%
5/17/2011	6	82	55	60%
5/27/2011	1	11	114	9%
5/27/2011	2	54	71	43%
5/27/2011	3	7	128	5%
5/27/2011	4	47	83	36%
5/27/2011	5	93	42	69%
5/27/2011	6	22	99	18%
5/27/2011	7	53	101	35%

The MSA also considered whether there was evidence the AESO's *Supply Surplus Report* reduced the number of actual events occurring. The report was introduced on December 8, 2010. The MSA is supportive of measures that avoid the AESO intervening in the market. However, the evidence is limited in suggesting that the report has resulted in an avoidance of supply surplus to date. The AESO experienced IT problems from late on May 16 through to early on May 17 that prevented the *Supply Surplus Report* from being updated. A simple analysis of the surplus hours on May 27 does not suggest a very significant decline in $0 offers from hours prior to supply surplus (or in comparison to hours after surplus). From HE21 to HE22 there was a decline of 109 MW which could be attributed to participants taking note of the surplus report. Most of the observed decline is accounted for by the curtailment of imports as shown in Table 2.5. Ultimately, it's up to market participants as to whether they respond to the signal provided through the *Supply Surplus Report*.

Table 2.5: Available MW at $0, Comparison between Surplus and Non-Surplus Hours

	Date	HE	Pool Price	Available MW at $0 [A]	MW away from surplus*	Net Imports after curtailment [B]	Curtailed Imports	[A]-[B]
	5/26/2011	13	30.95	5728	1786	318		5410
	5/26/2011	14	19.5	5942	1170	513		5429
	5/26/2011	15	17.28	5974	1172	497		5477
	5/26/2011	16	16.2	5935	1121	487		5448
	5/26/2011	17	19.29	5852	1326	488		5364
	5/26/2011	18	19.36	5804	1366	450		5354
	5/26/2011	19	15.16	5867	1028	450		5417
	5/26/2011	20	13.1	5932	858	510		5422
	5/26/2011	21	12.7	5956	745	514		5442
	5/26/2011	22	12.84	5848	778	515		5333
	5/26/2011	23	12.51	5850	533	514		5336
	5/26/2011	24	12.09	5805	232	463		5342
Supply Surplus Events	5/27/2011	1	3.08	5807	0	464	0	5343
	5/27/2011	2	0	5609	30	315	150	5294
	5/27/2011	3	0	5570	0	264	175	5306
	5/27/2011	4	0	5483	-5	265	175	5218
	5/27/2011	5	0	5476	0	264	200	5212
	5/27/2011	6	0	5657	0	365	100	5292
	5/27/2011	7	3.41	5933	0	464	0	5469
	5/27/2011	8	14.61	5770	745	294		5476
	5/27/2011	9	18.38	5792	1137	345		5447
	5/27/2011	10	19.26	5760	1308	294		5466
	5/27/2011	11	21.24	5801	1495	285		5516
	5/27/2011	12	19.39	5890	1320	350		5540
	5/27/2011	13	19.41	5886	1361	350		5536

* This calculation is based on a merit order snapshot taken in the middle of the hour and may contain instances where issuance/acceptance of dispatches may not have kept up with recent availability changes.

The utility of the *Supply Surplus Report* is likely to be enhanced as the AESO improves its price forecast methodology (e.g. inclusion of a forecast of wind generation). The MSA also notes that as we approach surplus conditions the possibility of supply surplus several hours into the future is often predicted and this appears to be a consequence of offer practices (and curtailments on the intertie). The MSA recommends the AESO consider whether improvements are possible in this area.

The limited number of $0 events during Q2/11 has not provided an opportunity to fully explore the practical application of the procedures embedded within OPP 103. Whilst the frequency of these events continues to be relatively low, it should rise with the increased amounts of wind in the system. In Section 2.4 we examine the frequency of 'close to supply surplus' events and conclude that it is possible to detect an upward trend in the first half of 2011.

2.2.1.7 Supply Shortfall Events in Q2/11

There was only one occasion in Q2/11 when the AESO was forced into Emergency Alert 1 conditions. It occurred on June 29th and lasted from 11:52 am to 12:18 pm, some 26 minutes. It was caused by a combination of high demand, derated import capability and a significant amount of coal capacity being off-line due to various reasons.

2.3 WIND EVENT

2.3.1 Event Description

The MSA continuously updates its tools as part of its on-going monitoring of the Alberta Market to ensure that market outcomes are consistent with the *fair, efficient and openly competitive* standard set out in section 6 of the EUA. Recently with the growing importance of wind as part of the Alberta generation mix, the MSA began to monitor the output of wind generators as one of its metrics.

Wind generation at a particular site is a function of the available capacity, wind speed and any transmission constraints imposed by the AESO. The MSA has access to information from the AESO on the constraints placed on wind generators but making an assessment of the impact of other factors is more difficult. For example, presently the AESO has little wind speed data available from the various wind farms and is relying on other data for its forecasting of wind output, which may be many kilometers from the farms monitored. As a simple metric, until more wind speed data is available, the MSA monitors wind output amongst wind farms in a common locale and if significant aberrations occur between wind farms the MSA will go back to the market participant to ask about the incident and/or request wind speed data to better understand the event.

In Alberta typically high priced periods tend to be reflective of periods of time when wind output is low or non-existent as noted in previous quarterly reports. The MSA, as part of its monitoring, detected an anomaly in that while market prices were high, as a result of significant unit outages on the system, there was also a significant amount of wind energy contributing to the system. What was observed was the fact that two of the wind farms owned by a participant appeared to have reduced their output. The MSA established that the significant reduction in output was not caused by an AESO transmission-related direction. Figure 2.5 shows the wind farm production of several farms in a locale and shows the reduction at HE13 and HE14.

Upon request, the participant willingly provided the wind data to the MSA. Figure 2.6 illustrates the wind output and wind speed. Figure 2.5 illustrates changes in output at two sister wind farms in comparison to other wind farms in the locale. To the MSA it was not clear why the dispatch for the two wind farms went to 0 MW output. Without the actual wind speed data it was hard to corroborate a theory that the two wind farms could have:

- Dispatched themselves off for economics and physically withheld the energy, or
- The output was reduced due to hi-speed cutout as it was too windy.

Figure 2.5: Wind Farm Production

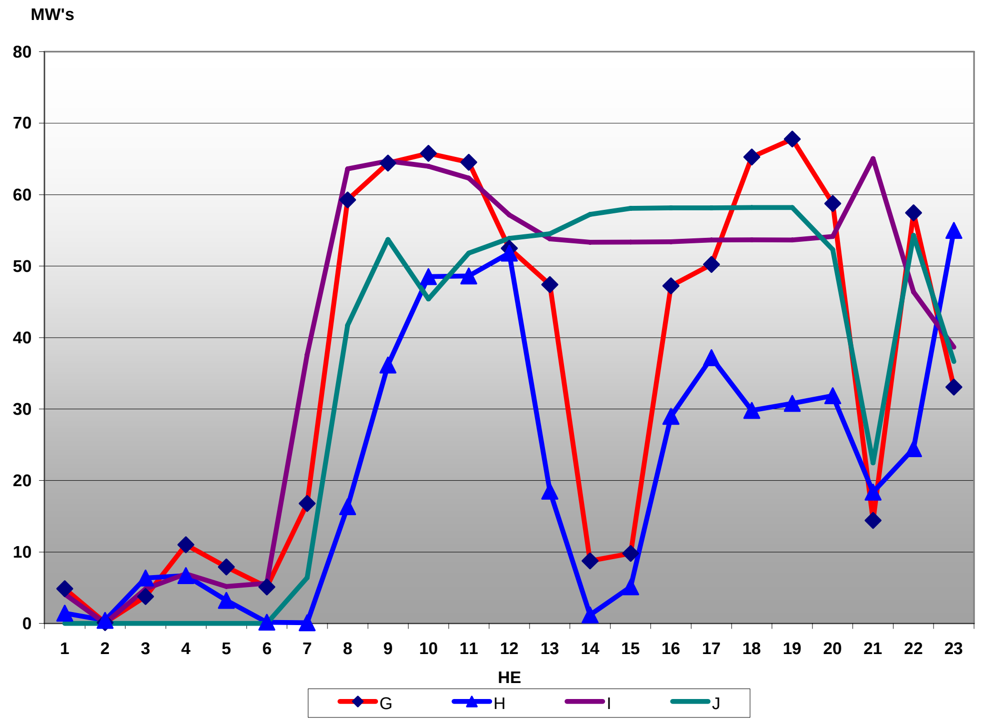
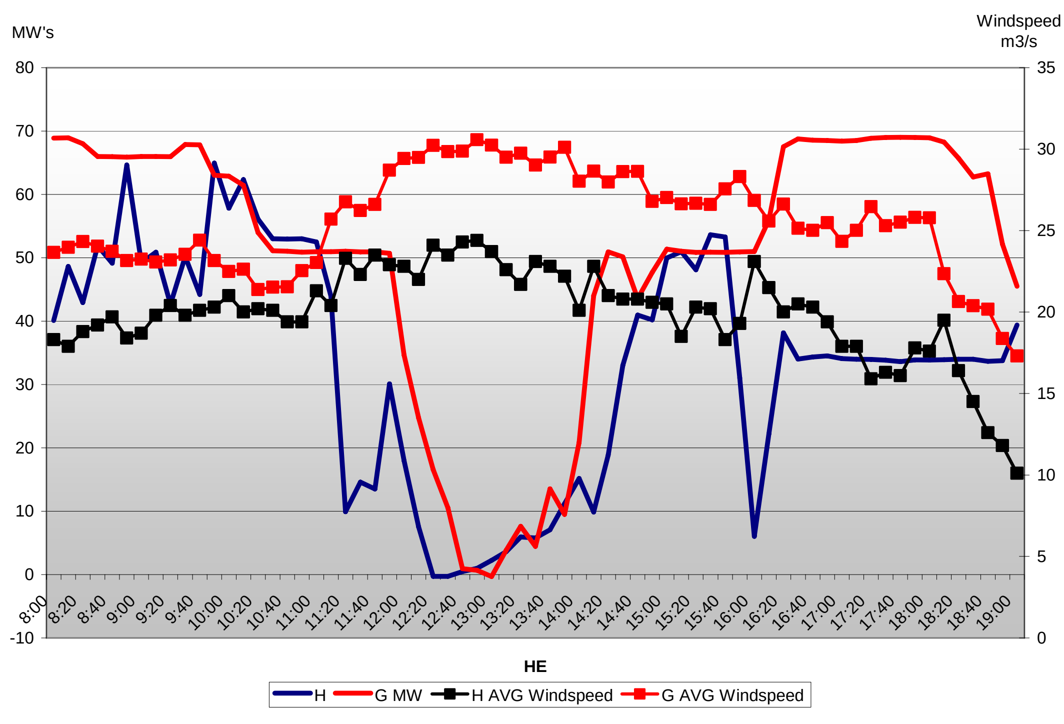


Figure 2.6: Wind Farm Production and Wind Speed



After making enquiries of the market participant, the MSA confirmed that the wind turbines at the wind farms in question experienced a high wind speed cutout. At very high wind speeds, typically greater than the 25 m/s range a wind turbine will shut down. Having a cutout speed is a safety feature which protects the wind turbine from damage.

2.3.2 Potential Concerns about Physical Withholding at Wind Generating Assets

While in this instance the MSA is satisfied that there was an operational reason for the reduction in wind output, it does raise the question as to whether a market participant, choosing to curtail output without an operational reason (akin to physical withholding), should face enforcement action from the MSA.

Offering of generation is subject to section 2(f) of the *Fair, Efficient and Open Competition Regulation*, which states:

> (f) not offering to the power pool all electric energy from a generating unit that is capable of operating, except where
> (i) the electric energy is used on property for the market participant's own use,
> (ii) the electric energy has been accepted by the ISO for the provision of ancillary services, or
> (iii) the *Electric Utilities Act*, its regulations or the ISO does not require the electric energy to be offered;

Subject to the exceptions contained within this section, this forms a prohibition against physical withholding. The MSA has previously expressed the view that market participants are free to pursue individually profit maximizing behaviour that does not impact on rivals' conduct, which includes strategies typically described as economic withholding.[1]

While, physical withholding is clearly prohibited, the MSA considered whether wind generation has an exception from Section 2(f) on the basis that the "ISO does not require the electric energy to be offered". On November 27, 2007 a letter from the AESO stated that:

> The application of ISO rules 3.2, 3.5 and 6.6 to wind generation facilities is deferred until forecasting, power management and compliance rules for wind are further developed and implemented. Rules 3.2, 3.5 and 6.6 will subsequently be updated to reflect the rules for wind generators.

No rules respecting the offering of wind generation have yet been passed; however, the AUC noted more recently that:

> The offer practices of wind may be well known in industry, but based on the submissions in this proceeding, and the absence of authoritative documents on the subject of wind being required or allowed to offer to the power pool, there is some confusion as to what rules wind is following or is exempt from following. Accordingly, the Commission finds that there are no exemptions set out in the ISO rules exempting wind generators from the application of the rules.[2]

The Commission's findings were in reference to section 3 and this does not necessarily extend to subsection 2(f) of the FEOC Regulation.

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[1] *OBEG's, p19.*

[2] *AUC, 2010-0426, para 46.*

The MSA observes that it could be seen as inconsistent with market participant obligations for a wind generator, who is able to run, to physically curtail in order to not run, simply for economic reasons.

We await further specification as the AESO works through the policy and rule development process now underway. In the event that the MSA were to detect, or have reported to us, instances where wind units were intentionally curtailed, other than for operational reasons, we would consider the matter seriously.

2.4 MERIT ORDER ANALYSIS

This section describes analysis of different aspects of the hourly energy market merit order looking for trends and patterns that may be of interest.

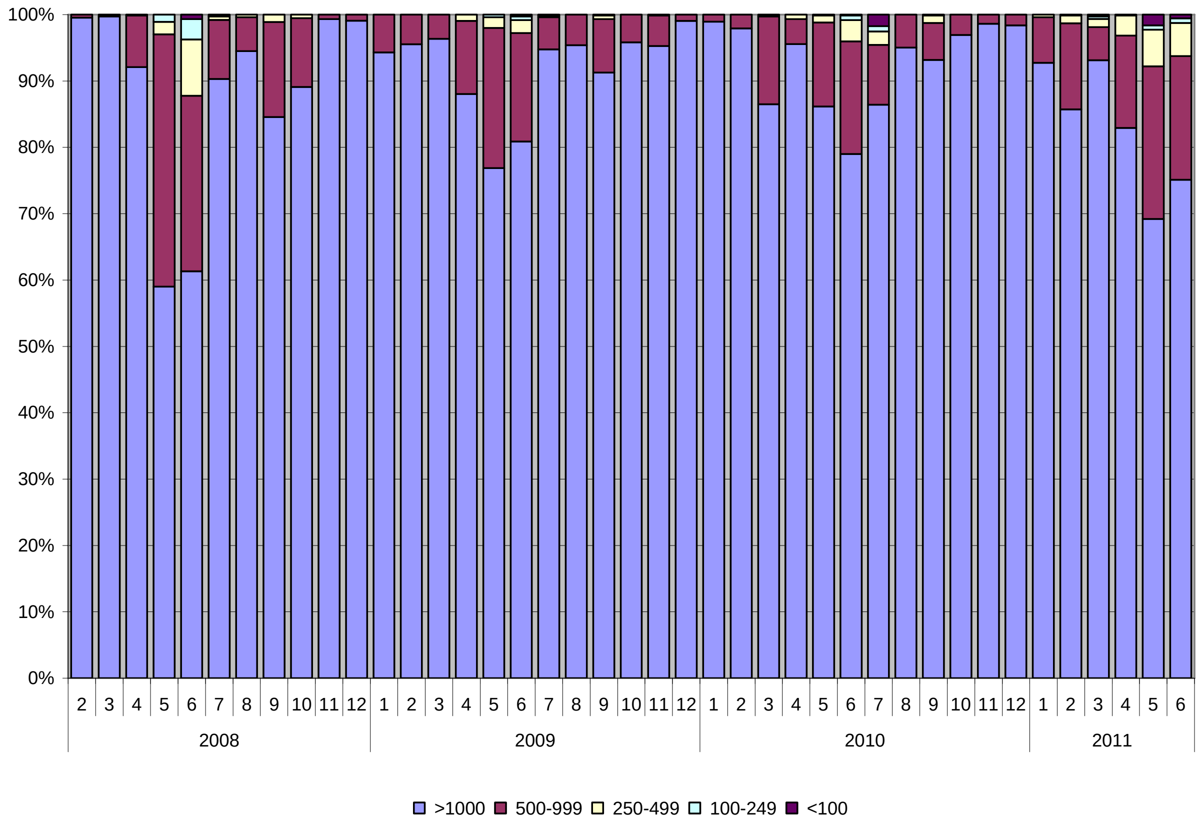
2.4.1 Frequency of Close to Supply Surplus Conditions

Whilst there were a number of occasions of supply surplus in Q2/11, the frequency of $0 price events remains low. For purposes of comparison, in 2010 there was only one $0/MWh pool price event, with a larger number of hours with a $0 SMP and where OPP103 resulted in the curtailment of imports. Given the low frequency and the difficulty in identifying supply surplus events where pool price remained above $0/MWh, we have taken a different approach to determine whether the market is trending towards more supply surplus events.

For each hour from February 2008 until the end of June 2011 we measured the number of priced MW between the mid-hour SMP and the first block of $0 energy. Figure 2.5 shows the percentage of hours in each month in the different buckets, the smaller the size of bucket the closer the hour was to being a supply surplus hour. It appears that May and June experience the highest incidences of close to supply surplus conditions. There appears to be some indication of an upward trend in the first half of 2011 compared with the same period in recent years.

Note that a high frequency of close to surplus hours does not necessarily suggest a low average pool price. For example, while May and June 2008 featured a large number of close to surplus hours, average pool price for the month was $103.73/MWh and $83.00/MWh respectively. As noted many times in the MSA's quarterly reports, high average prices for a month are primarily driven by events that tighten the market and cause significant elevations in pool price for a limited number of hours. Supply surplus conditions that prevail in a few hours make very little difference to the monthly average pool price.

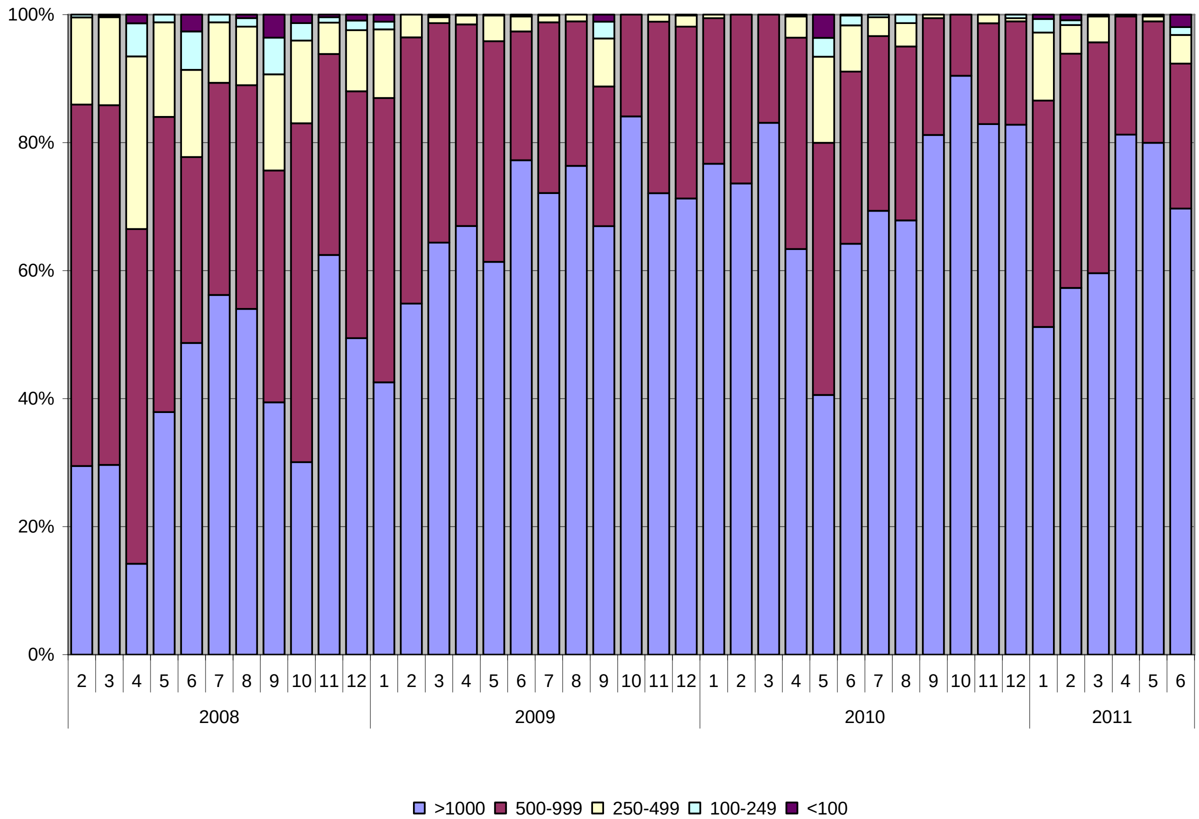
Figure 2.5: Monthly Distribution of Close to Surplus Events



2.4.2 Frequency of Close to Supply Shortfall Conditions

A similar analysis can also be presented by looking at the number of hours where the market was close to shortfall conditions. This analysis uses the MSA's supply cushion metric and Figure 2.6 shows the results. Conditions in the first half of 2011 show an increase in the number of hours close to shortfall, compared to the same period in 2010 (with the notable exception of April and May 2010 when transmission outages resulted in generation capacity being unable to participate in the market).

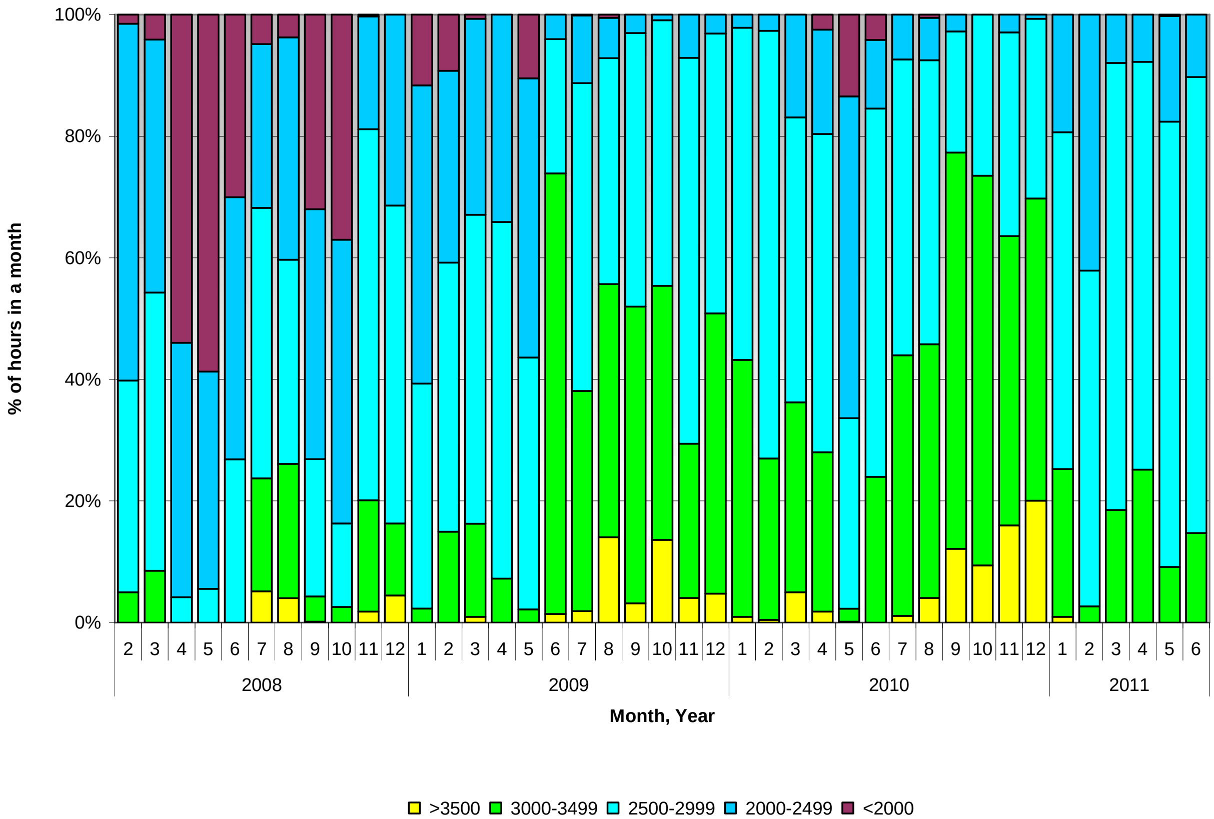
Figure 2.6: Monthly Distribution of Close to Shortfall Events



2.4.3 Merit Order Depth

An increase in the frequency of both close to surplus and close to shortfall conditions is not unprecedented (see, for example, 2008) and is related to the depth of the merit order (measured by the number of MW priced at greater than $0/MWh). Merit order depth is shown graphically in Figure 2.7. The majority of hours in 2011 feature merit orders with a depth of between 2500 and 3000 MW, less than much of 2009 and 2010. Shallowness of the merit order is also a factor in explaining price volatility and in determining whether a given level of economic withholding would be profitable for a market participant.

Figure 2.7: Monthly Distribution of Merit Order Depth



2.4.4 Discussion

The MSA does observe a shift 2011 towards conditions close to surplus and shortfall, consistent with a reduction in the depth of the merit order. Increased wind development, in the absence of rules that allow capacity to offer at prices, is likely to exacerbate the trend towards surplus conditions. The commissioning of Keephills #3 is likely to weaken the trend towards surplus (and shortfall) as the unit moves from testing ($0/MWh offers) towards full availability and the ability to accept dispatch.

3 Retail Market

3.1 ENERGY PRICE SETTING PLANS FOR RRO CUSTOMERS

3.1.1 Introduction

Close to 75% of small consumers in Alberta (consumption less than 250 MWh/year), with approximately 9,500,000 MWh of total demand in 2010, have not signed a competitive contract with a retailer. By default their energy is supplied via a Regulated Rate (RRO) Provider for their service area. Each RRO Provider must establish an Energy Price Setting Plan (EPSP) in accordance with the *Regulated Rate Option Regulation*. The EPSPs for utilities must be approved by the Alberta Utilities Commission.

The EPSPs are thus an important part of the Alberta retail landscape. Further, due to the design of the RRO and its prompt month pricing structure, there is a strong link to the near-term forward market and the spot market. The MSA has an on-going interest in the performance of the Regulated Rate Option (RRO) and the EPSPs and therefore this section provides a comprehensive summary of the past and current processes.

Presently the Regulated Rate:

- Reflects the forward market view of pool prices and fluctuates on a monthly basis;
- Is determined based on a market view of the commodity, unlike transmission costs on a consumers bill where prices are based on cost of service;
- Has a significant price volatility reflecting the forward market's view of upcoming supply and demand fundamentals; and,
- Is published by the AUC on the first day of each applicable month for utilities that it regulates, and all RRO Providers must themselves publish the Regulated Rate each month.

The EPSPs provide the consumer with no price guarantee beyond the current month. This distinguishes the RRO from many competitive contracts offered by retailers which fix the energy costs for a longer period of time and provide price certainty to the consumer.

For utilities regulated by the AUC, the EPSP's price setting mechanisms are a negotiation between the RRO Provider in a service area, the Independent Advisor (IA) and the Consultation Parties (primarily the Consumers Coalition of Alberta and the Utility Consumer Advocate).

The negotiated settlements were reviewed and approved by the AUC. On July 1, 2011 the three largest RRO Providers - Direct Energy Regulated Services (Direct), ENMAX Energy Corporation (ENMAX)[3] and EPCOR Energy Alberta Inc. (EPCOR) implemented new Energy Price Setting Plans for the three year period starting July 1, 2011 and ending on June 30, 2014 (2011-2014 EPSP).[4] The 2011-2014 EPSPs superseded the EPSPs that were in effect during the period from July 1, 2006 to June 30, 2011 (2006-2011 EPSPs).

The fundamental difference between the pre-July 1, 2011 plans and the present plans is that, during four of their five years, the old plans included a rate blend of a longer term hedge and a gradual increase in the proportion of a monthly forward hedge. This was done to provide some price stability in the period 2006 to 2010 and to phase out the existing longer term hedges. The new EPSPs are based strictly upon the monthly forward hedge, the idea being that the consumer that prefers more price stability should consider signing with a competitive retailer.

The following paragraphs compare the 2011-2014 EPSPs to the 2006-2011 EPSPs in order to identify changes that have been made. As well, we provide some initial comments, where appropriate, on our observations about the early performance of the new EPSPs. Information used in preparing the report was obtained from Orders and/or Decisions of the Alberta Energy and Utilities Board (EUB or Board), the AUC and information responses of the RRO Providers in various regulatory proceedings pertaining to the

[3] *ENMAX is currently operating under interim approval pending Commission approval of its proposed EPSP for the period 2011 to 2014.*

[4] *For the purpose of preparing the report, we do not discuss the energy price setting plans that are the responsibility of the owners of municipal distribution systems or rural electrification associations.*

EPSPs. Some components of the EPSPs related to energy procurement are confidential due to issues regarding commercial sensitivity and, accordingly, we have not commented on these provisions.

3.1.2 2006 to 2011 Energy Price Setting Plans

This section describes the previous EPSPs for the three largest RRO Providers, those regulated by the AUC.

3.1.2.1 Energy Procurement[5]

Each of the RRO providers used a market based procurement process for the term portions (referred to as Other Procurement Arrangements in the RRO Regulation) of the required supply during the transition period from July 2006 to June 2010. After that, between July 1, 2010 and June 30, 2011, the RRO price was entirely based upon the forward month price.

ENMAX and EPCOR both used full load auctions operated by the Natural Gas Exchange (NGX), while Direct used a block procurement process for procuring 7x24 Flat and 7x16 Peak Products derived from their load forecasts.

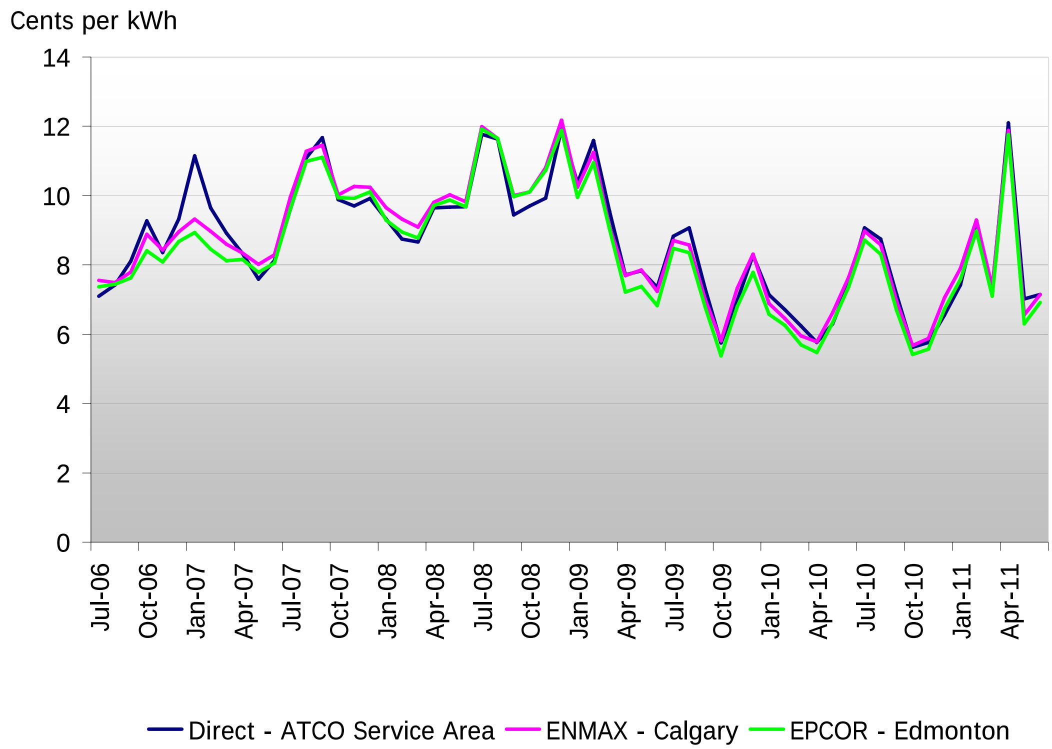
EPCOR and ENMAX, which both owned generation at the time, supplied the RRO at Index prices derived by the NGX. However, Direct which did not own generation, procured their supply requirement through purchases of Flat and Peak Products during the pricing period (i.e., the period beginning on the 45th day preceding the RRO month and ending on the 5th business day preceding the RRO month).

Figure 3.1 below indicates that the EPSPs for the three RRO Providers produced very similar and consistent results over the 2006 to 2011 time period. In fact, as the procurement methodology moved to a greater and greater degree of monthly forward procurement the plans fell more and more in step. The remaining differences in EPSPs are the negotiated "costs of procurement" as illustrated in the Table 3.1 below under Incentives to Supply.

While the various methodologies to create the RRO prices differed in the 2006 to 2011 period, little difference existed in the calculated RRO Rates, an indication of the competitive nature of the Index.

[5] *AUC Proceeding 567, Fulton Opening Statement, Exhibit Number 0179.00.DEML-567, page 1.*

Figure 3.1: Monthly RRO Rates for the Three Major Providers



3.1.2.2 Differences among 2006 - 2011 Energy Price Setting Plans[6]

The differences among the EPSPs were primarily in the negotiated risk and return margin treatment that reflected the underlying customer classes for each RRO Provider and their preferences with respect to the treatment of risk and return margins. EPCOR and Direct have significantly more customer classes than ENMAX and set monthly rates for each class. ENMAX sets only one rate for both their residential and commercial customers. Other differences in the risk margin included differences in components related to peak consumption, seasonal loads and line losses.

Table 3.1 summarizes and compares the key components of the previous EPSPs for the three RRO Providers.

[6] *Ibid, page 1.*

Table 3.1: Key Month-Ahead Components of 2006 to 2011 Energy Price Setting Plans

EPSP Component	Direct	ENMAX	EPCOR
Procurement Self Supply	100% Block procurement through forward swap agreements that settle against the Pool Price.	100% self-supply - 70% based on Flat and Peak NGX Indices, 30% based on EEC Index	100% self-supply based on NGX RRO Indices.
Price Setting Methodology	Index Price based on Cost of Contracts and Swaps	Index Price based on NGX Indices	Index Price based on NGX Indices
Back Stop Arrangement	None	None	None
Incentives to Supply Fixed Compensation for Risk			
Risk Compensation	\$1.50+(Max(\$65,Peak Price)-\$65)*0.035	\$4.30/MWh	Annual change from \$2.175/MWh in the first year to \$1.875/MWh in the last year
Administrative Risk Compensation	\$732,604/year	\$1.25/MWh	\$0.41/MWh
Hourly Load Shape Compensation	\$1.59+(Max)\$65,Peak Price)-\$65)*0.05		
Variable Compensation for Risk		1.25% Additional 2.75% in Superpeak months	3.25%, additional 2.05% for Nov 2009 to Feb 2010 Superpeak months and 2.05% for Nov 2010 to Feb 2011 Superpeak months (applicable only to last 7 Superpeak months)
Incentive Component	Incentive for performance of posting to NGX, credit limit reporting, daily reporting and periodic reports - \$50,000 per month at discretion of IA	ENMAX Index incentive (minimum 1.25%, maximum 4.5%) for narrowing of spreads on Flat and Peak Indices - applied to 30% of load	Liquidity incentive to enhance market participation; \$0.20/MWh on Flat Products and \$0.125/MWh on Peak Products, if thresholds met, Peak Liquidity Incentive weighted by Peak Portfolio Volume
Return Margin			
Going Concern Return Margin		\$0.75/MWh (at risk)	
Load Obligation Return Margin		\$0.75/MWh	
Energy Return Margin	\$1.75/MWh[1]		\$0.65/MWh (Pre-tax)
Other Compensation			
Negotiation / Plan Implementation	Flow through of actual costs	Included in Administrative Risk Compensation	Flow through of actual costs

EPSP Component	Direct	ENMAX	EPCOR
Credit Costs	Flow through of actual costs	Included in Administrative Risk Compensation	Composite of $0.0145/MWh weighted for full load percentage and $0.002/MWh weighted for month ahead percentage.
Pool Trading Charges	Flow through of AESO charge	Included in Administrative Risk Compensation	Flow through of AESO charge
Retailer Adjustment to Market Charge	Included rolling historic 12-month average into forecast monthly rate	Included in Administration Risk Compensation	Average of the last 12 months of RAM charges incurred divided by the RRO Load Forecast for the month
AESO Uplift Charge	Not accounted for in negotiated risk and not recovered	Rolling 12-month average actual	Average of last 6-months of actual Uplift divided by RRO Load Forecast for the month[2]
Payment in Lieu of Tax Regulation	NA	Flow through of actual costs on return margins only	NA

Notes:

1. After tax

2. Method used in the last couple of months. Before, Uplift was forecasted by formula.

Sources:

AUC Proceeding ID No. 1077, Direct Information Response AUC-DERS-007

AUC Proceeding ID No. 1032, EPCOR Information Response AUC-EEAI-11

Discussions with Direct, ENMAX and EPCOR

3.1.3 2011 to 2014 Energy Price Setting Plans

The discussion in this section is based on AUC Decision 2011-199 for the Direct EPSP, AUC Decision 2011-123 for the EPCOR EPSP covering EPCOR Distribution and Transmission Inc. and Fortis Alberta service territories, and AUC Decision 2011-208 which provides interim approval to ENMAX which allows ENMAX to provide the RRO until such time as the Commission approves ENMAX's application for its proposed EPSP.

The energy procurement methodologies along with the negotiated 'costs of procurement' in the 2011 through 2014 EPSPs are markedly different from one another.

3.1.3.1 Energy Procurement

Direct - 2010 RRO sales were 1,638,000 MWh

Under the terms of its EPSP, Direct is responsible for procuring its energy supplies under the direction and with the input of the Consultation Parties and the Independent Advisor (IA).[7] Direct forecasts the month ahead metered load and total load and acquires block hedges (Peak and Base Products) of sufficient volume to hedge the forecast total load. The cost of the procured hedges forms the basis for determining the monthly energy rate.[8]

The block hedges are forward swap agreements that settle against the Power Pool hourly prices.[9] Direct may acquire its RRO hedging requirements directly from third parties, from third parties through brokers and directly on NGX. Direct does not plan to use periodic auctions and is not relying on a NGX Daily Index.[10]

The IA provides each day a daily maximum price and a daily target volume for a base load product and a peak product and an off-peak product. Direct may procure those products as bilaterals or may buy off the NGX. The total volume to procure is supplied by Direct based upon a forecast. The intent is that a minimum of 90 percent of such volumes will be procured within the first 30 days of the price setting period.[11]

The energy cost component of the regulated rate paid by consumers is determined on the basis of the Off-Peak Energy Portfolio Cost and Peak Energy Portfolio Cost as determined pursuant to the Energy Charge Schedule in the Energy Price Setting Plan.[12]

Direct has no backstop mechanism if insufficient energy has been procured through the market, the assumption being that the forward market is always liquid at some price.

EPCOR - 2010 RRO sales were 5,600,000 MWh

In the previous EPCOR EPSP, a major component was based on self-supply priced at an Index price. EPCOR, by spinning off its generation component to Capital Power, can no longer self supply. As a result EPCOR must procure the required RRO energy from the market.

Energy supply procurement in the EPCOR EPSP involves using an NGX hosted platform to host a series of auctions within the price setting period to acquire 7x24 Base and 7x16 Peak Energy Products. This procurement mechanism is similar to that employed in the 2006-2011 EPSP.[13] In the case of EPCOR, which has by far the largest RRO load, the procurement process does not involve the need for the IA to set price or quantity. There are three auctions run on the NGX (plus a contingency auction if needed) in which:

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[7] *Ibid, DERS Information Response, AUC-DERS-014*
[8] *Ibid, paragraph #30, page 8.*
[9] *Ibid, DERS Information response, TCE-DERS-002.*
[10] *Ibid, DERS Information response, TCE-DERS-002.*
[11] *Ibid, page 4.*
[12] *Ibid, Appendix 2, page 14.*
[13] *Ibid, page 7.*

- A seed price is established (a price to beat) based on several measurable factors. If market prices are above the seed price no energy is bought in that auction;
- The overall volume for both the Flat (7x24) and Peak (7x16) products is forecasted by EPCOR; and,
- The Auction is deemed to be 'competitive' by EPCOR. If not deemed competitive the auction is terminated and no energy is bought.

There is a backstop mechanism that EPCOR will use if it is unable to acquire enough base and peak energy products for the upcoming month through the NGX auction process. Any remaining volumes will be supplied to EPCOR from a third party outside of the NGX auction process. The costs associated with relying on the backstop mechanism will be flowed through to customers with a margin added.[14] The backstop supplier was selected through a request for proposal process.[15]

EPCOR bids for base and peak loads rather than full loads.[16] The timeframe over which the NGX Auction Sessions are conducted moved from once or twice per quarter to three times per month. The first two phases of the auction the posting, removing and adjusting of offers phase and the decreasing offer phase, have been shortened from 5 and 5 minutes to 3 minutes and 2 minutes, respectively.[17]

The energy price for the month for each of the energy products procured will be the weighted average of the prices resulting from the NGX Auction Sessions[18] Plus any backstop volumes and prices if required.

ENMAX (Interim) – 2010 RRO sales were 2,294,000 MWh

In ENMAX's EPSP application to the Commission, it requested that if approval could not be provided by May 13, 2011, the Commission should approve an interim mechanism that would be in place until such time as the Commission approved the EPSP.[19]

The Commission determined that the most suitable option for use by ENMAX during the transition period is to continue the existing EPSP during the transition period, modified to remove the ENMAX Indices and related compensation, as suggested by the IA.[20]

ENMAX – Application

ENMAX's proposed EPSP is substantially similar to the procurement process put forward by Direct. In this regard, ENMAX develops a load forecast, and then during the Price Setting Period, procures blocks of Flat Products and Peak products sufficient to hedge the RRO load, using Target Prices and Target Volumes set by the IA and in consultation with the CPs.[21] The monthly forward market electricity prices

[14] *Ibid, page7.*
[15] *EPCOR Information Response, TCE-EEAI-02*
[16] *Ibid, page 7.*
[17] *Ibid, page 8.*
[18] *Ibid, Appendix 2, page 27.*
[19] *AUC Decision 2011-208, page 1.*
[20] *Ibid, page 8.*
[21] *ENMAX Energy Corporation, 2011-2014 Regulated Rate Option Energy Price Setting Plan Application, Negotiated Settlement, April 19, 2011, page 9.*

will be established based on actual procurement using the target pricing methodology during the Price Setting Period.[22]

There is no requirement for ENMAX to procure blocks of energy from any particular market participant and thus they may self supply. ENMAX may only self-supply as the backstop supplier under specific conditions and circumstances outlined in the confidential Appendix 3 of the EPSP.[23]

ENMAX's EPSP proposal also includes a backstop process. The CP and IA agreed that ENMAX could provide its own backstop. Under this process, if a prescribed portion of the RRO Portfolio for the Price Setting Period has not been procured by a prescribed period of time, the balance of the RRO Portfolio will be procured in accordance with the confidential backstop procurement process set out in Appendix 3. The price for energy is the weighted average contracted price of all blocks; including the price of any offers that ENMAX is deemed to have accepted under the procurement process.[24]

3.1.3.2 Differences among 2011 to 2014 Energy Price Setting Plans

Table 3.2 compares the 2011 – 2014 EPSPs for the three RRO Providers.

Table 3.2: Comparison of 2011 to 2014 Energy Price Setting Plans

EPSP Component	Direct	ENMAX	EPCOR
Procurement / Self Supply	100% Block procurement through forward swap agreements using daily target volumes and prices set by the IA	100% procurement of Flat and Peak forecast volumes using daily block procurement volumes and target prices as set by the Independent Advisor	100% procurement through the NGX hosted auction system to procure both Flat and Peak products
Price Setting Methodology	Forwards settle as swaps against the Power Pool Hourly Price	Forwards Settle as swaps against Pool Price	Forwards Settle as swaps against pool Price.
Back Stop Arrangement	No Backstop mechanism	Self Backstop, confidential arrangement	Chosen Via RFP, confidential arrangement
Fixed Compensation for Risk			
Risk Compensation	$2.97/MWh	$3.50/MWh	$2.11/MWh
Administrative Risk Compensation	$800,000/year	$0.61/MWh	$0.41/MWh

[22] *Ibid, EEC Information Response, CPC.EEC-003*
[23] *Ibid, EEC Information Response AUC.EEC.020*
[24] *Ibid, Appendix 1, pages 5 - 6.*

EPSP Component		Direct	ENMAX	EPCOR
Variable Compensation for Risk		1.50%	2.25%	3.35%
Incentive Component		Maximum of $30,000/month as determined by the IA.	Shared mechanism if transacted price is less than the Target Price for Products acquired under Procurement Process and if transacted price is less than NGX Price Indices for Products acquired under the Backstop Procurement Process	Liquidity Incentive equal to 10% of the difference between Base NGX Price Index and Base Portfolio Cost or Peak NGX Price Index and Peak Portfolio Cost weighted by corresponding Base or Peak Portfolio Volumes
Return Margin				
	Going Concern Return Margin		$1.00/MWh MWh (at risk)	
	Load Obligation Margin		$0.50/MWh	
	Energy Return Margin	$1.75/MWh[1]		$1.38/MWh (After tax)
Other Compensation				
	Negotiation / Plan Implementation	Flow through of actual costs	Included in Administrative Risk Compensation	Flow through of actual costs
	Credit Costs	Flow through of actual costs	Included in Administrative Risk Compensation	Forecasted quarterly based on 7x24 product price and credit rate for a drawn facility.
	Pool Trading Charges	Flow through of actual costs	Flow through of actual costs	Flow through of actual costs
	Retailer Adjustment to Market Charge	Direct at risk for RAM and included in Risk Compensation	Rolling 12-month average actual	Average of the last 12 months of RAM charges incurred divided by the RRO Load Forecast for the month
	AESO Uplift Charge	Direct at risk for Uplift and included in Risk Compensation	Rolling 6-month average actual	Average of last 6-months of actual Uplift divided by RRO Load Forecast for the month
	Payment in Lieu of Tax Regulation	NA	Flow through of actual costs	NA

Notes:

1. After tax

Sources:

AUC Proceeding ID No. 1077, Direct Information Response AUC-DERS-007

AUC Proceeding ID No. 1174, ENMAX Information Response AUC.EEC-025

AUC Proceeding ID No. 1032, EPCOR Information Response AUC-EEAI-11

Discussions with Direct, ENMAX and EPCOR

3.1.4 Comparisons between 2006 to 2011 EPSPs and the 2011 to 2014 EPSPs

Direct

The current EPSP for Direct removes all references to term volumes throughout the EPSP and includes a provision to procure a minimum of 90 percent of the required volumes within the first 30 days of the energy price setting plan.[25]

The Commission noted, based on Direct's response to AUC-DERS-7(a), that the monthly bill impact on a customer's bill under the proposed EPSP versus the existing EPSP represents a change of generally less that one-tenth of one percent.[26] The procurement protocol adopted in the 2011-2014 EPSP is essentially the same procurement protocol used in the 2006-2011 EPSP.[27]

EPCOR

One of the major changes to the EPCOR EPSP is that EPCOR has divested itself of its generation to Capital Power and, as a result, EPCOR can no longer self supply this load but must buy the energy from the market.

EPCOR's EPSP is expected to result in an average total bill increase of 1.24 percent for residential customers in EPCOR Distribution & Transmission Inc.'s service territory and a 1.04 percent average increase for residential customers in FortisAlberta Inc.'s service territory.[28]

ENMAX – Application

ENMAX estimated that the proposed EPSP would result in a 3.23 percent reduction in residential rates and a 2.26 percent reduction in commercial rates compared to the current EPSP.[29] For comparative purposes, ENMAX used the current pricing methodology for both existing and proposed calculations and indicated the total bill impacts are related to compensation, margin and Local Access Fees.[30]

3.1.5 MSA Role Going Forward

Operation of the new EPSPs began in May 2011 and it is too early to make a proper assessment of performance. We have observed that the EPCOR auctions have been experiencing difficulty attracting sufficient offers to enable effective competition for supply. This situation appears to be related to the calculation of the seed price for the auction. Note that the seed price is effectively the price cap for the particular auction (A subsequent amendment to the EPSP approved by the AUC should address this concern). The MSA has also observed that the Flat block size for the auction, at 25 MW, is much larger than what typically trades on the NGX. Allowing smaller block sizes may encourage more participation.

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[25] *Ibid, DERS Information Response AUC-DERS-034*

[26] *Ibid, page 7.*

[27] *Ibid, DERS Information Response, AUC-DERS-034*

[28] *Ibid, page 6 updated by EPCOR to reflect a formula correction approved in Decision 2011-259.*

[29] *Note that the energy rates for residential and commercial class customers are the same for ENMAX. The differences here relate to total bill excluding transmission and distribution costs.*

[30] *Ibid, ENMAX Information Response AUC.EEC-004*

The MSA is concerned that the failure of the auctions to attract sufficient interest may mean that EPCOR's EPSP would not meet the test of a *fair, efficient and openly competitive* acquisition process as required under the RRO Regulation. In regard to this situation, we wrote to the AUC in support of a proposed amendment to EPCOR's 2011 – 2014 EPSP which is intended to address the issue of the seed price creation. On July 22, 2011, EPCOR obtained approval from the AUC, Decision 2011-314, to amend the seed price mechanism. Despite the difficulties observed in the August auction procurement process, EPCOR successfully procured all of its load requirements through the auction mechanism

In general, the NGX Index appeared to work well in the period 2006 through 2011 as the proportion of prompt month energy gradually ratcheted up to 100%. The MSA is hopeful that this will continue to be the case. Some examples of items that would raise a flag for the MSA would be an increased premium between the forward index and spot prices or regular run up or fall off of prices in or near the RRO price setting window. In such cases, the MSA would seek to understand the reasons for the observed effect.

The MSA views the performance of the EPSP auctions in the broader context of the functioning of fair, efficient and openly competitive market operations in Alberta. The perceived shortcomings of the recent auctions may simply reflect flaws in auction design, or it may suggest underlying concerns with the overall competitiveness of the market. The MSA will continue to take an active interest in the performance of the EPSPs.

3.2 CODE OF CONDUCT AUDITS

A key component of our retail monitoring activity takes place in relation to the *Code of Conduct Regulation* (Code). The electricity Code was enacted under the *Electric Utilities Act* to help ensure a level playing field for electricity retailers. In this regard, the Code governs the relationships between owners of electric distribution systems and their affiliated retailers, as well as dealings with non-affiliated retailers, customers and customer information.

The Code contemplates that owners and affiliated retailers will undergo a compliance audit on an annual basis. There is a degree of discretion available to the MSA as to how such auditing is carried out and typically we have conducted the audits in association with professional auditors relying on our ability to obtain information and conduct testing pursuant to our overall surveillance and investigation mandate under the Act.

In 2011, we will be conducting audits of four market participants (owners and affiliated retailers). The specific period being tested is July 1, 2010 through June 30, 2011, inclusive. As in previous audits, the test period was chosen to avoid carrying out the audits during the first quarter of the calendar year – a time which tends to be very busy in relation to year end financial and other audits.

The testing plan will focus on sections 3, 7, 17, 18, 20, 21 33, and 34 of the Code. These Code sections deal with the conduct of owners and retailers; advertising; business practices of owners and retailers; preventing unfair competitive advantages; and adherence to and accuracy of compliance plans. If necessary, we will pursue additional matters should they arise during the course of the audits.

The testing will be carried out during the months of August and September. The audit findings will be shared and discussed with the relevant parties during October and related reports finalized and published toward the end of this year.

4 Electricity Forward Market

The forward financial market is an important venue for the market participants to hedge price risks. Both generators and loads use financial contracts to hedge against the volatility of the pool price. The detailed mechanism of how to use the forward financial market to hedge price risks was previously described by the MSA.[31]

In Alberta, financial power contracts are settled against pool price and at any given time the prices at which forward contracts are traded are based on the expectations of pool price for the product being traded. The Regulated Rate Option for smaller electricity customers not on competitive contracts is established based on the costs of the monthly financial power instruments. As a result, the forward financial market becomes a juncture where potential issues with the spot market or the retail market may expose themselves. For this reason, the MSA does not monitor the forward financial market in isolation. We monitor the forward financial market in the context of the activities related to the spot market and the RRO pricing/procurement process.

4.1 NEW STYLE OF STANDARD FORWARD MARKET REPORT

Recently the MSA developed a forward financial trading database that enables the monitoring of trading volumes, prices, participation and the positions of individual participant in a more efficient way. With the database, the MSA is able to provide more detailed information in Appendix E of the quarterly report.

In Figure 4.1, the market participants are categorized into different groups: Generator, Marketer/Load and Banks/Funds. 'Generators' includes participants who own generating assets in the province. 'Marketer/Load' includes those who either have some obligation to service load or have loads themselves. 'Banks/Funds' are the trading entities set up by banks or private funds and commonly called speculators.

Figure 4.1 also features the inclusion of the direct bilateral volumes – the volumes that are not transacted through brokers but are settled through and reported by Natural Gas Exchange (NGX). In order to accommodate the fact that during a given period, the volumes purchased and the volumes sold by each participant group are not equal, the total volumes in Figure 4.1 include both the buy side and the sell side to better reflect the actual trading volume share. In previous quarterly reports, the total volumes only include one side of the transactions. Another change is the inclusion of a new graph (Figure 4.2) that shows the percentage shares of trading volumes of each of the three groups of participants.

4.2 OBSERVATIONS OF THE FORWARD MARKET

In the past a few months, the MSA observed a noticeable change in the forward financial contract trading. Figures 4.1 and 4.2 illustrate the monthly trading volumes and market shares over the past two years. Along with the decreased overall liquidity, the trading volume share of the Banks/Funds has also dropped in the past year. This decrease shows that the drop in trading activities of the Banks/Funds was greater in magnitude than the other two groups.

[31] MSA Report, 'An Introduction to Alberta's Financial Electricity Market', 2010.

Figure 4.1: Forward Financial Market Trading Volume[32]

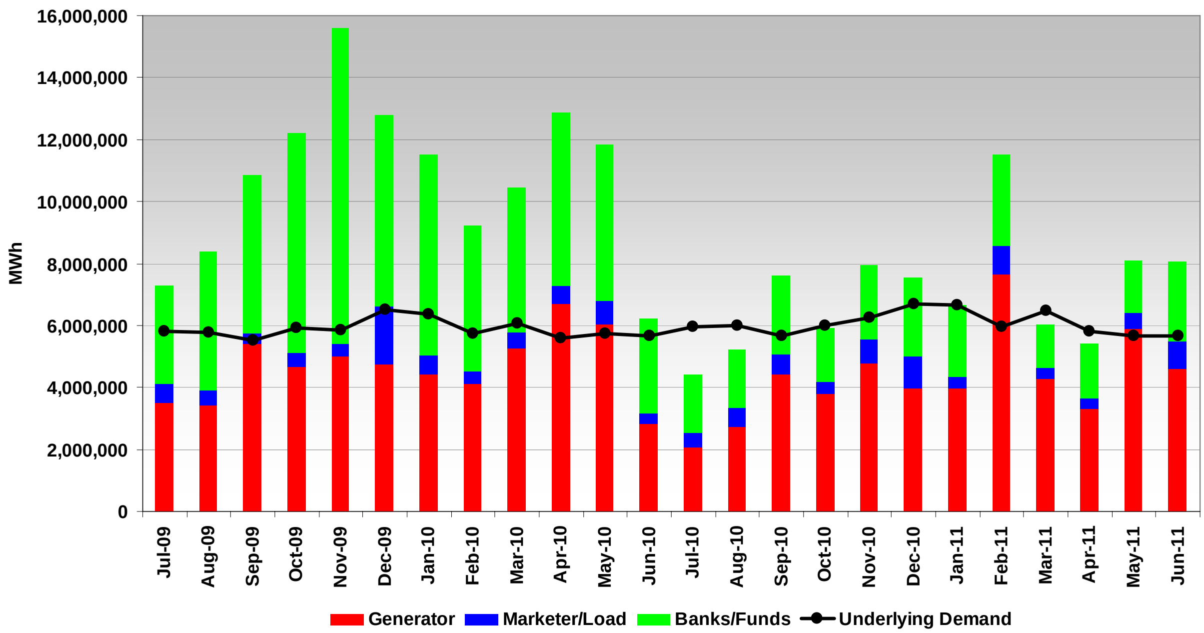
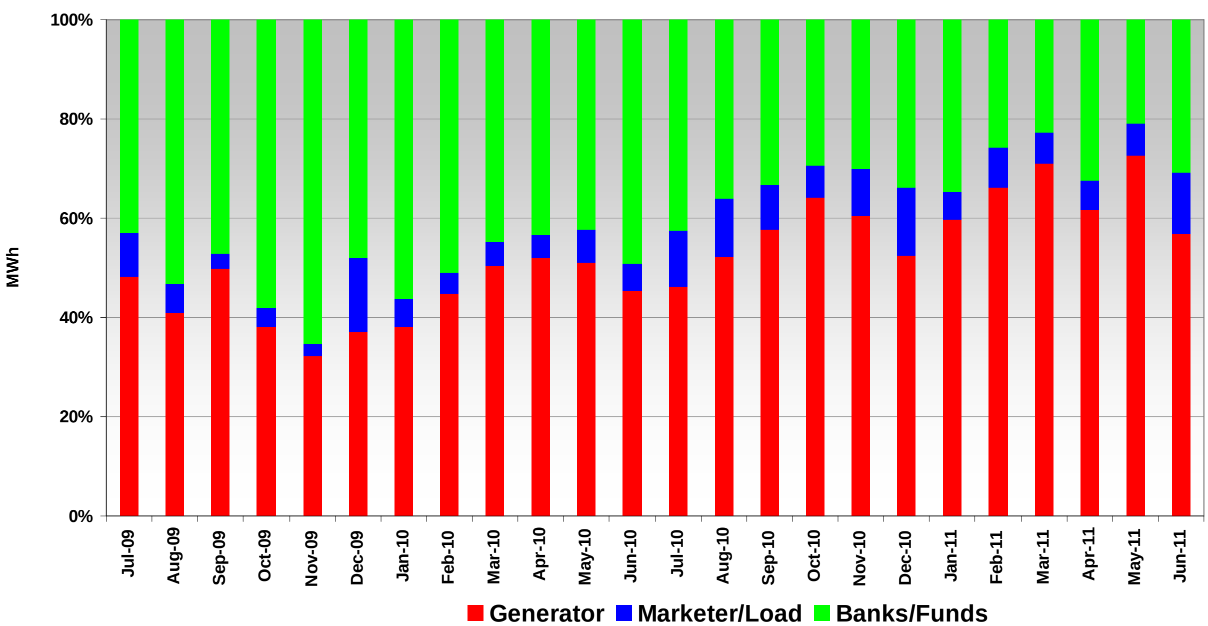


Figure 4.2: Financial Market Trading Volume Market Share

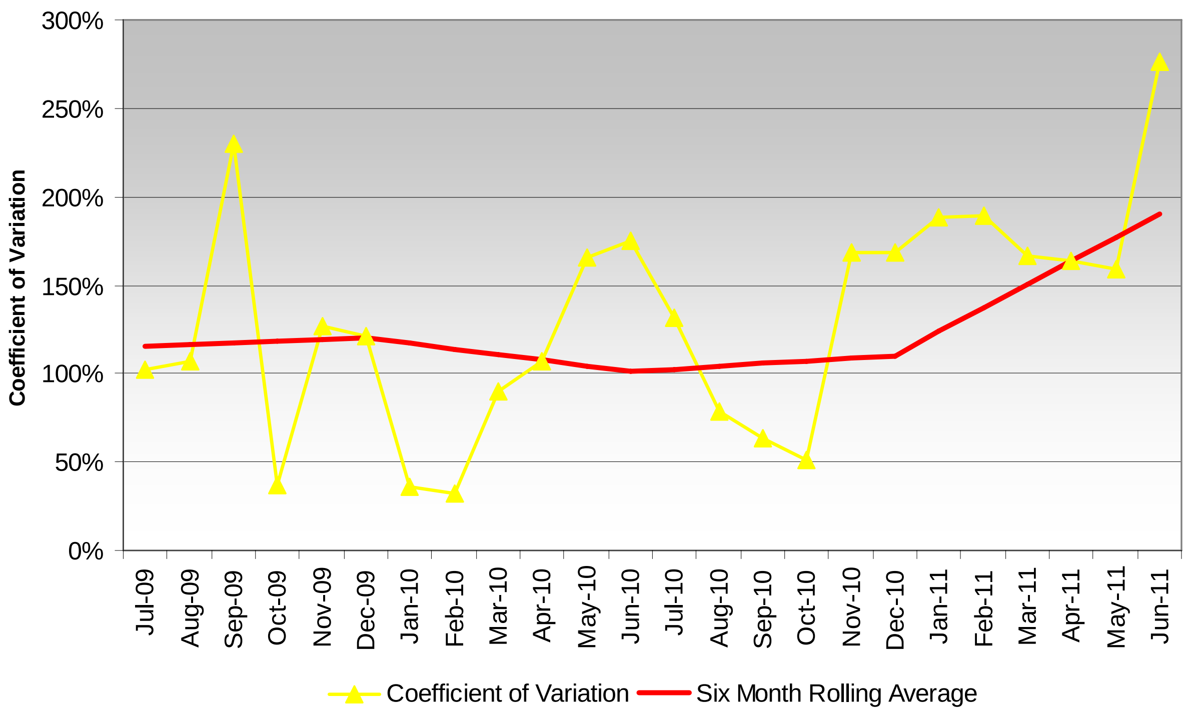


One reason for the reduced liquidity, especially for the Banks/Funds, is the increased perceived risk in the market. For example, the increased pool price volatility caused the market participants to believe that the market risks have increased. The MSA regularly publishes the volatility metric, Pool Price Coefficient of Variation, in its quarterly reports. Figure 4.3 is a summary of the coefficient of variation of the hourly pool price by month and the six-month rolling average in the past 24 months. It is obvious that the pool price

[32] *Since the total volume plotted include both the buy side and the sell side, the ratio of the forward trading volume to the underlying demand should be divided by half when comparing with graphs in the previous quarterly reports.*

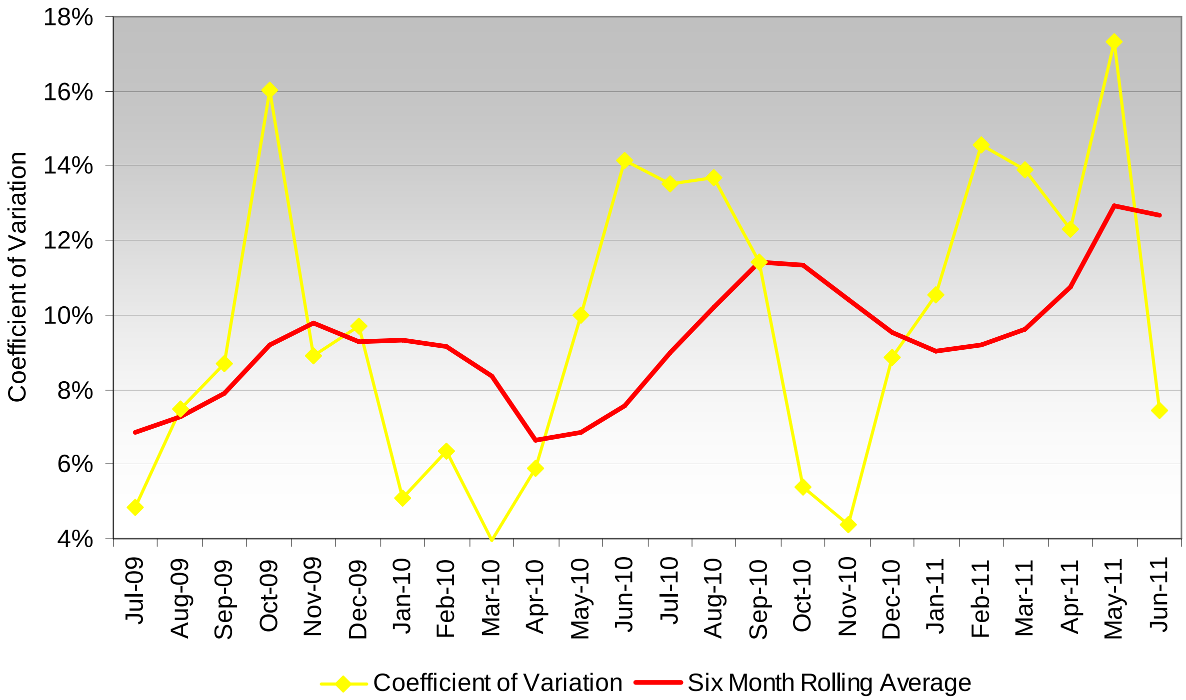
volatility increased in recent months. The increased volatility hampered the trading activities, especially those of the Banks/Funds who do not own generating assets and have no abilities to use generating assets to influence pool prices. All speculative traders are given trading limits to protect the company from high losses. For a given trading limit, the amount of volatility in the market directly impacts the amount of trading that can be done. Either the trader trades less volume or gets 'stopped out' (meaning reaches the trade limit) and cannot participate for a period of time. As a result, along with the overall decrease in liquidity, the liquidity from the Banks/Funds dropped faster.

Figure 4.3: Coefficient of Variation of Hourly Pool Prices



The forward price is expected to reflect the market view of the spot pool price in the future. In a liquid market, the change in the forward contract price is typically driven by market information related to the demand and supply of the spot market. However, in a less liquid market, changes in the forward financial contract prices are also susceptible to the trading activities of participants whose positions are relatively large in comparison with other participants. This adds another source of volatility in the forward prices. Over the past year, the forward financial contract price has become more volatile, evidenced by the increased coefficient of variation in trade prices. Figure 4.4 shows the coefficient variation of the daily volume-weighted average trade prices on NGX and the broker's market, by month and 6-months rolling average. An upward trend is evident from the graph.

Figure 4.4: Coefficient of Variation of the Flat Monthly Contract Price



Higher risks increase the cost of hedging and add increased risk premium to the forward price. For example, the longer term forward financial contract price had been stable, on a market heat rate basis, until recently when the relationship saw a structural shift from 9 to 10 heat rate levels to nearly 15. Figure 4.5 shows the forward market heat rates in Alberta as of the end of the year (for 2011 it's as of the end of June) and there has been an upswing which can only partly be assigned to the uncertainty surrounding Sundance #1 & #2. Whilst it might be that these high Alberta prices are simply a strong signal for new investment, for the first 10 years of the market (in its current form) a heat rate of 9 to 10 seemed to provide the same signal. It should be noted that the ISO's Long Term Adequacy (LTA) metrics were most recently updated in early August 2011 and suggests a tightness in the market over the next two years if Sundance #1 and #2 do not return to service.[33]

The risk premium built into the forward price is more prominent with the near term contracts, evidenced by the fact that the forward financial Alberta flat power contract prices are significantly above the peak power contract prices in markets across the Western markets (Figure 4.6).

[33] *"Long Term Adequacy Metrics, August 2011", AESO.*

Figure 4.5: Longer-Term Forward Market Heat Rates in Alberta

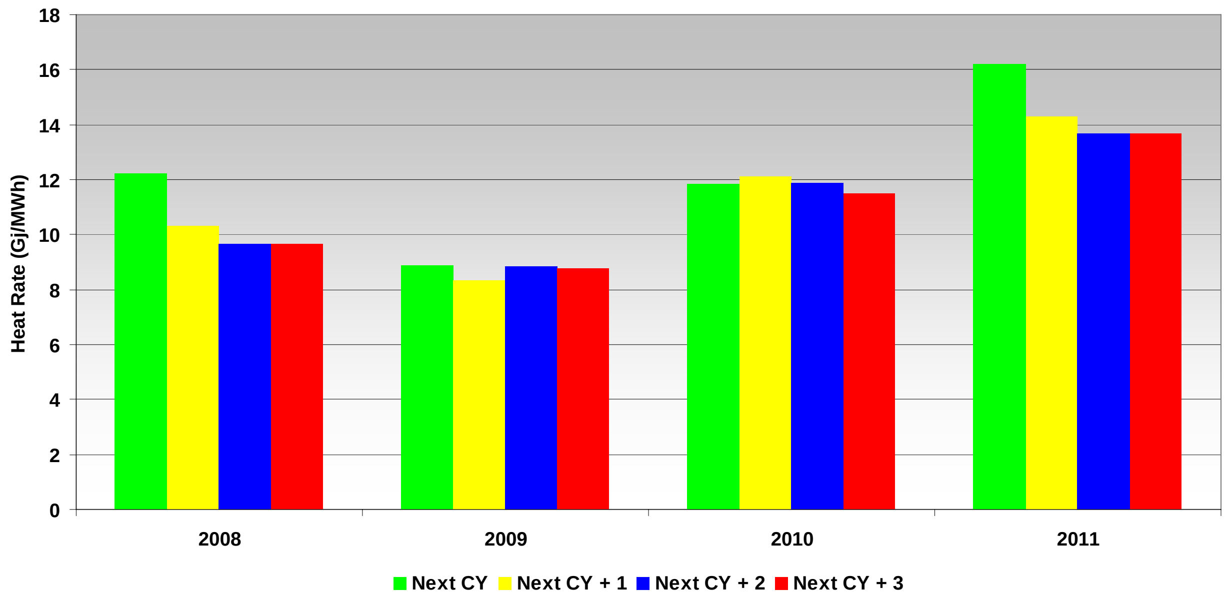
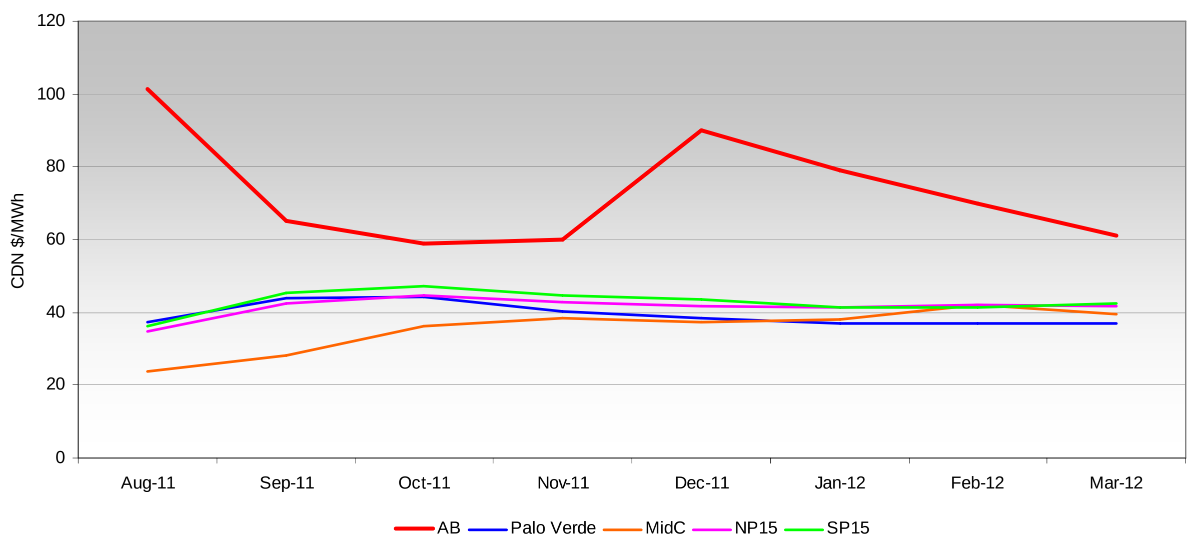


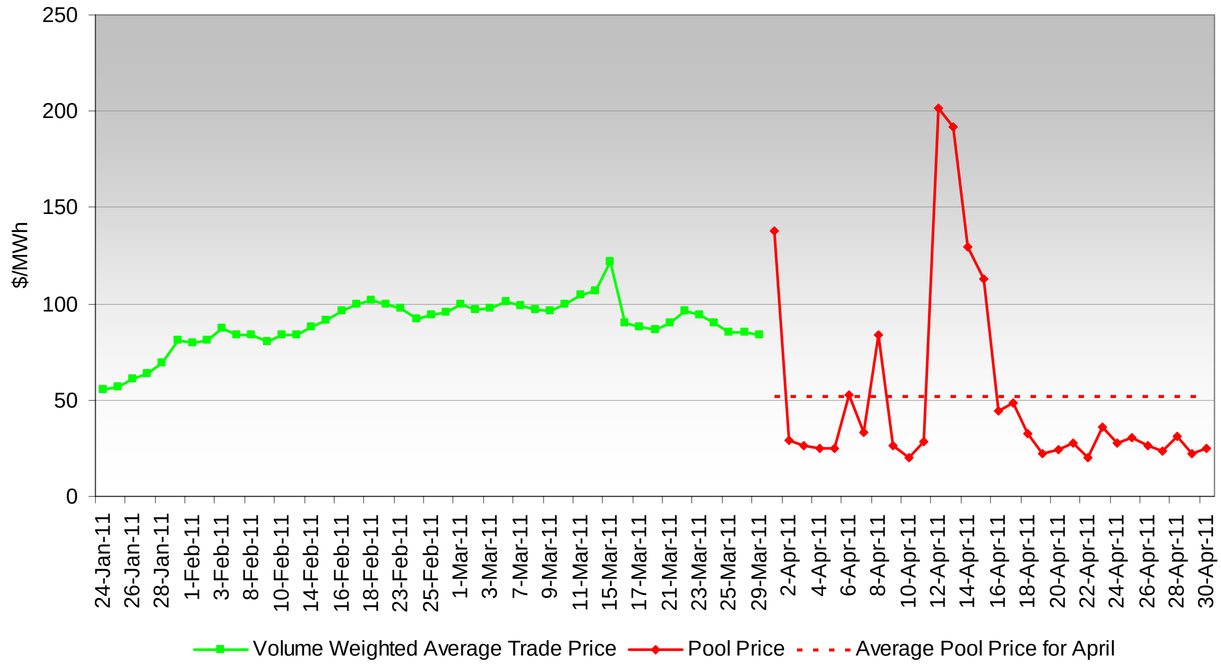
Figure 4.6: Near-Term Forward Contract Prices (As of end of Q2/11)



4.3 THE EVOLUTION OF THE APRIL CONTRACT

The evolution of the April contract attracted the attention of the MSA as the contract was marked with a price pattern that ran up by over $65/MWh between late January and mid-March, before dropping by about $40/MWh when the contract entered into the settlement month (i.e. April). Even with the $40/MWh drop, the last trading price of the April contract was more than $30/MWh higher than the average pool price in April (Figure 4.7).

Figure 4.7: The April Flat Monthly Contract Price (NGX and Brokers) and the April Pool Price



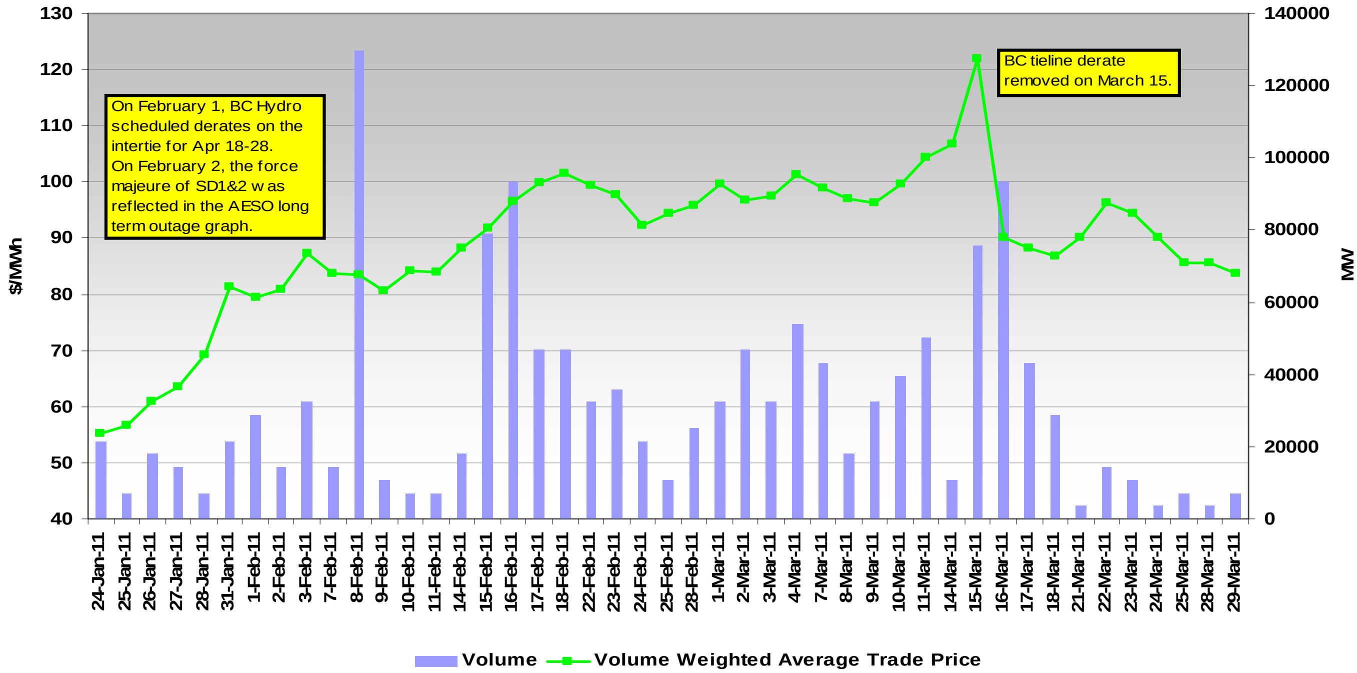
The movements in the April contract price were largely caused by market information relating to the market fundamentals in April (Figure 4.8).

On January 21, the AESO's "*Keephills 3 Interconnection and Edmonton Region 240kV Line Upgrades – Project Update*" indicated that a planned outage at 1202L transmission line would limit Keephills-Ellerslie-Genesee (KEG) cut plane (KGC) from 2450 MW to 1440 MW between April 1 and April 19. The transmission limit was expected to constrain the output of the coal-fired units in the KEG area. As a result, as soon as the April contract started to trade in late January, the price increased.

Further upward pressure on the April contract price occurred on February 1 when BC Hydro scheduled a derate of the AB-BC intertie for April 18 - 28. On February 2, the AESO Monthly Outage graph incorporated the *force majeure* of Sundance #1 and #2, showing a significant increase in outages of the coal-fired generating units in April. On the next trading day, the price of the April contract rose by more than $6/MWh.

In mid-March, however, the April contract price reversed its upward trend and started to drop. Triggering this reversal was that on March 15, BC Hydro cancelled the derate on the AB-BC intertie originally scheduled for April. This caused a sell-off of the April contract on March 16, which drove the price down by over $31/MWh.

Figure 4.8: The Evolution of the April Contract Price – NGX and Brokers



Notwithstanding the price reductions in the last two trading weeks in March, the April contract still managed to expire at $83/MWh, more than $30/MWh higher than the subsequent average April pool price. Note that the average pool price in April was low by historical standards. The average pool price in April 2011 ($52.23/MWh) is the fourth highest in the past 15 years: 2000 ($93.68/MWh), 2001 ($114.80/MWh) and 2008 ($135.95/MWh).

In April 2000 and 2001, the California energy was in full swing with its knock-on effect on all the western markets. Here in Alberta at that time there was genuine scarcity of generation further putting upward pressure on pool prices.

In April 2008, the KEG area transmission project severely restricted the output of the coal-fired units between mid March and the end of June. The project caused the tightness of the market. Out of the total of 720 hours in April 2008, there were 241 hours when the supply cushion dipped below 500 MW. The tightness of the market resulted in the highest April average price. The price movements of the April 2011 contract appeared to display a pattern as if the market expected a repeat of the circumstances that prevailed in April 2008. However, the average supply cushion in April 2011 was more than double that of April 2008. The average pool price for April 2011 was $87/MWh lower than in April 2008.

It is unlikely that the forward market collectively ignored the fact that the fundamentals related with the demand and supply balance were different in April 2011 from those in April 2008. It is apparent that the risks associated with the spot market as perceived by the market participants trumped the known information about the supply and demand fundamentals. The overwhelming risks built into the forward prices prevented the convergence between the April contract price and the actual spot price in April.

5 Compliance Activities

5.1 ISO RULES COMPLIANCE

Table 5.1 provides an update of the MSA's ISO rules compliance activities as of the end of Q2/11. During the first six months of 2011, the MSA issued 28 notices of specified penalty. In 100 other cases, the MSA chose to forbear, 12 other matters remained under review, while two matters are proceeding through the administrative penalty process. Additionally, 2 referrals remain under review, each of which contains multiple suspected contraventions of ISO rule 3.5.3 during 2010. Due to the unique nature of these two matters, they have been excluded from Tables 5.1 and 5.2. For comparison, in the first 6 months of 2010, the MSA had issued 24 notices of specified penalty, 28 forbearances and had 10 files under review. One hundred and thirty-one new files were opened in the first half of 2011 which is more than double the 59 files opened during the first half of 2010.

Table 5.1: Compliance Files (as of end of Q2/11)

	Under Review	Notice of Specified Penalty	AUC Administrative Proceedings	Forbearance
3.5.3	4	1		10
3.5.5	4		2	2
3.6.2				
5.2.2				
6.2.2	2	1		
6.3.3		16		40
6.4.3	1			
6.5.3		4		4
6.6	1	6		41
OPP 102				2
OPP 402				1
Total	12	28	2	100

The contravention dates of the 28 notices of specified penalty issued during the first half of 2011 ranged from July 2010 through May 2011. Twenty-three of these notices of specified penalty were issued in cases where a suspected contravention was referred by the AESO. Four notices of specified penalty were issued in cases where a non-compliance matter was self reported but the self report did not satisfy the MSA's criteria to forbear. In two of these four cases, the matter was deemed to be a recurring problem within a short duration of time while the other two matters were deemed to be of a more serious nature. One additional matter was identified and brought to the market participant's attention by the MSA and then self reported but consequently not recognized as a self report. Table 5.2 segments the second, third and fourth columns of Table 5.1 by month of contravention date.

Table 5.2: Q2/11 Compliance Files by Month of Contravention

	Rule	2010 Jul	2010 Aug	2010 Sep	2010 Oct	2010 Nov	2010 Dec	2011 Jan	2011 Feb	2011 Mar	2011 Apr	2011 May	2011 Jun	Total
Under Review	6.6									1		1	2	4
	3.5.3									1	1	1	1	4
	3.5.5													
	3.6.2													
	5.2.2									2				2
	6.2.2													
	6.3.3												1	1
	6.4.3													
	6.5.3												1	1
	OPP 102													
	OPP 402													
	Total									4	1	2	5	12
NSP	3.5.3											1		1
	3.5.5													
	3.6.2													
	5.2.2													
	6.2.2					1								1
	6.3.3		2	3	5	1	2	3						16
	6.4.3													
	6.5.3	1						2			1			4
	6.6		1		1		2	2						6
	OPP 102													
	OPP 402													
	Total	1	3	3	6	2	4	7			1	1		28
Forbearance	3.5.3				1	1	3				2	3		10
	3.5.5				1					1				2
	3.6.2													0
	5.2.2													0
	6.2.2													0
	6.3.3			2	1	2	7	8	5	6	5	4		40
	6.4.3													0
	6.5.3							1		2	1			4
	6.6					3	4	10	7	6	9	1	1	41
	OPP 102							1	1					2
	OPP 402										1			1
	Total			2	3	6	14	20	13	15	18	8	1	100

5.1.1 Emerging Trends

During the first half of 2011 the MSA has received 96 self reports - a substantial increase from the 28 received in the first half of 2010. During Q2/11, 43 self reports were received which was down somewhat from the 53 received during Q1/11. The MSA is encouraged by the level of self reporting and views it as an outcome of market participants taking a proactive compliance approach and availing themselves of incentives to self report. These include a greater prospect of forbearance based upon specific criteria and also the reduction in applicable specified penalties per AUC Rule 019 when events are self reported.

During Q2/11, the MSA observed an increase in reporting time compared to Q1/11. Seven percent of self reports received in Q2/11 were submitted within 7 days of the non compliance event compared 30% in Q1/11. Fourteen percent of self reports were received within 14 days of the event compared to 55% in Q1/11. As a result, a number of participants were contacted by the AESO concerning an event that the participant had intended to self report. Participants are reminded that a self report needs to be received by the MSA prior to the participant being alerted to the matter by either the AESO or the MSA. Based upon compliance monitoring procedures, this could occur within 30 days of the event particularly in cases where a non-compliance event occurs near the end of the prior month. In addition, events of non-compliance that appear to be more serious in nature may be referred on an expedited basis. Accordingly, participants are advised to report matters of non-compliance promptly and not wait until the end of the 30 day period. If necessary, a participant can follow up a self report with additional information it considers relevant to the event.

Fifty-seven percent of notices of specified penalty and 40% of forbearances were related to ISO Rule 6.3.3 – Interconnection Dispatching. On March 17, 2011 the AESO posted a letter of notice on the consultation of proposed New ISO Rules Section 203.6 which included the removal of ISO Rule 6.3.3. In addition to other stakeholders, the MSA submitted comments in regards to this consultation which can be viewed on the AESO's website.[34] While those comments were supportive of refinements to rule 6.3.3, the MSA's ongoing approach has been to enforce the rules currently in effect until such time as rule changes are ultimately approved.

5.2 ALBERTA RELIABILITY STANDARDS

During the first half of 2011, the MSA received 25 self reported compliance matters relating to Alberta Reliability Standards (ARS). Thirteen matters related to PRC-001-AB-1, 9 matters were for contraventions of CIP-001-AB-1 and 3 matters regarded PRC-004-AB-1. The MSA has not yet received any referrals from the AESO in relation to a suspected contravention of a reliability standard since an AESO referral will arise predominantly from audit findings and compliance audits of registered entities began in Q2/11. The AESO itself will be subject to a reliability standards compliance audit during Q4/11 to be conducted on behalf of the MSA by WECC as contemplated in the MSA WECC Services Agreement.[35] No specified penalties have been issued thus far in relation to ARS compliance. A generally high caliber of self reporting and effective mitigation has provided a basis for forbearance in the cases reviewed to date. Compliance audits are a mechanism which will, in due course, test that the basis of forbearance was not materially misrepresented and that the entity has fulfilled any undertakings by way of non-compliance mitigation.

The nature of self-reporting and associated mitigation plans described above is laudable but there are two issues around compliance with CIP-001-AB-1 that bear attention by market participants.

First, this standard came into effect in Alberta on April 12, 2010 but surprisingly we continue to review instances of non-compliance over a year after its effective date. The MSA recommends that all registered entities review their sabotage reporting policy to ensure that it satisfies the requirements of ARS CIP-001-AB-1.

Secondly, when reviewing compliance with this standard, participants need to understand the separate nature of obligations embodied in CIP-001-AB-1 and other event-based ARS requirements. This would avoid unnecessary reporting of non-compliance. The MSA's view is that without an <u>event</u> triggering prescribed actions, that aspect of the ARS requirement is not contravened. For example, R4.2 of CIP-001-AB-1, requires registered entities to "implement the procedures as identified in requirement R4.1 <u>upon the occurrence of a sabotage event</u>." (emphasis added) If an entity had an inadequate procedure as identified in R4.1, and a sabotage event subsequently occurred, the entity would be considered in non-compliance with R4.1 and R4.2 otherwise the entity would be considered non-compliant only with R4.1.

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[34] *http://www.aeso.ca/downloads/2011-05-05_SH_Comments_Letter_(ATC).pdf*

[35] *MSA – WECC Service Level Agreement*
http://albertamsa.ca/uploads/pdf/Archive/Services_Agreement_MSA-WECC_041910.pdf

6 MSA Activities

6.1 ANNUAL REPORT ON MARKET SHARE OFFER CONTROL

In June, as required by the *Fair, Efficient and Open Competition Regulation*, the MSA published its annual report summarizing the control of assets in Alberta focused on the largest 6 market participants each with more than 5% market share. [36] The largest market participant in terms of control of assets in Alberta, as defined in the Regulation, is TransCanada with a market share of 19% Note that the regulation limits the maximum amount of control by any one firm to 30%.

6.2 EISG MEETING

In April, MSA staff participated in the first of the twice yearly meetings with our colleagues in the electricity market surveillance business. The Energy Intermarket Surveillance Group provides a private forum for the exchange of ideas and discussion of areas of mutual interest. Yes, there is a secret hand shake too.

6.3 FERC NOTICE OF PROPOSED RULE MAKING

The MSA joined other North American market monitors in a submission to the US Federal Energy Regulatory Commission, June 27, 2011, regarding the availability of E-Tag information (Docket No. RM11-12-000). The submission supported FERC's proposal to order access for its enforcement staff to comprehensive E-tag information that the Commission had said would aid it "…in market monitoring and preventing market manipulation, help assure just and reasonable rates, and aid in monitoring compliance with certain business practice standards…" The joint comments urged FERC to also extend access to this data to market monitors.

[36] *MSA Report, 'Market Share Offer Control 2011', June 24, 2011. http://albertamsa.ca/uploads/pdf/Reports/Reports/2011/Market%20Share%20Offer%20Control%20Report%20062411.pdf*

Appendix A: Wholesale Energy Market Metrics

Table A.1: Pool Price Statistics

Month	Average Price1	On-Pk Price2	Off-Pk Price3	Std Dev4	Coeff. Variation5
Apr-11	52.23	70.33	27.48	85.53	164%
May-11	32.27	43.92	17.50	51.29	159%
Jun-11	71.85	111.05	18.20	188.90	263%
Q2-11	**51.90**	**75.10**	**20.97**	**123.77**	**238%**
Jan-11	79.05	109.66	40.23	149.02	189%
Feb-11	122.45	182.94	41.79	232.14	190%
Mar-11	48.52	63.32	27.96	78.61	162%
Q1-11	**82.05**	**116.25**	**36.60**	**164.29**	**200%**
Apr-10	49.71	61.51	33.57	53.32	107%
May-10	134.69	193.55	60.03	223.19	166%
Jun-10	57.27	79.44	26.93	100.43	175%
Q2-10	**81.15**	**111.50**	**40.69**	**150.68**	**186%**

1 - $/MWh
2 - On-peak hours in Alberta include HE08 through HE23, Monday through Saturday
3 - Off-peak hours in Alberta include HE01 through HE07 and HE24 Monday through Saturday, and HE01 through HE24 on Sundays
4 - Standard Deviation of hourly pool prices for the period
5 - Coefficient of Variation for the period (standard deviation/mean)

Figure A.1: Pool Price Duration Curves

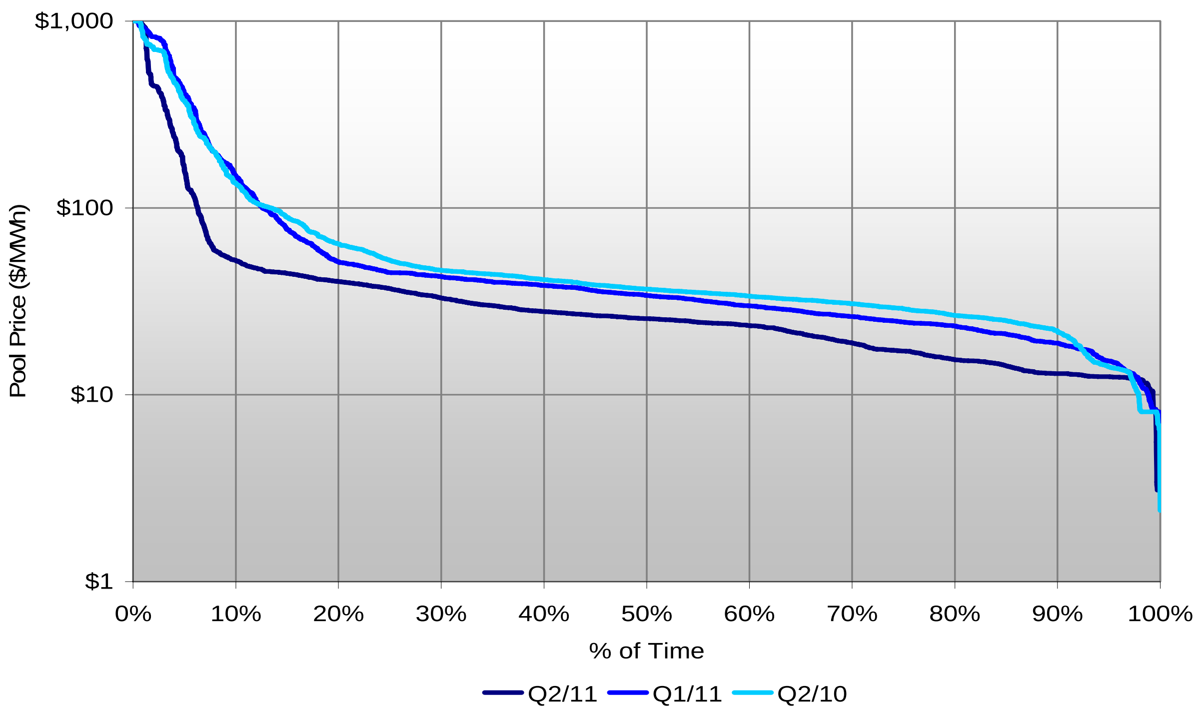
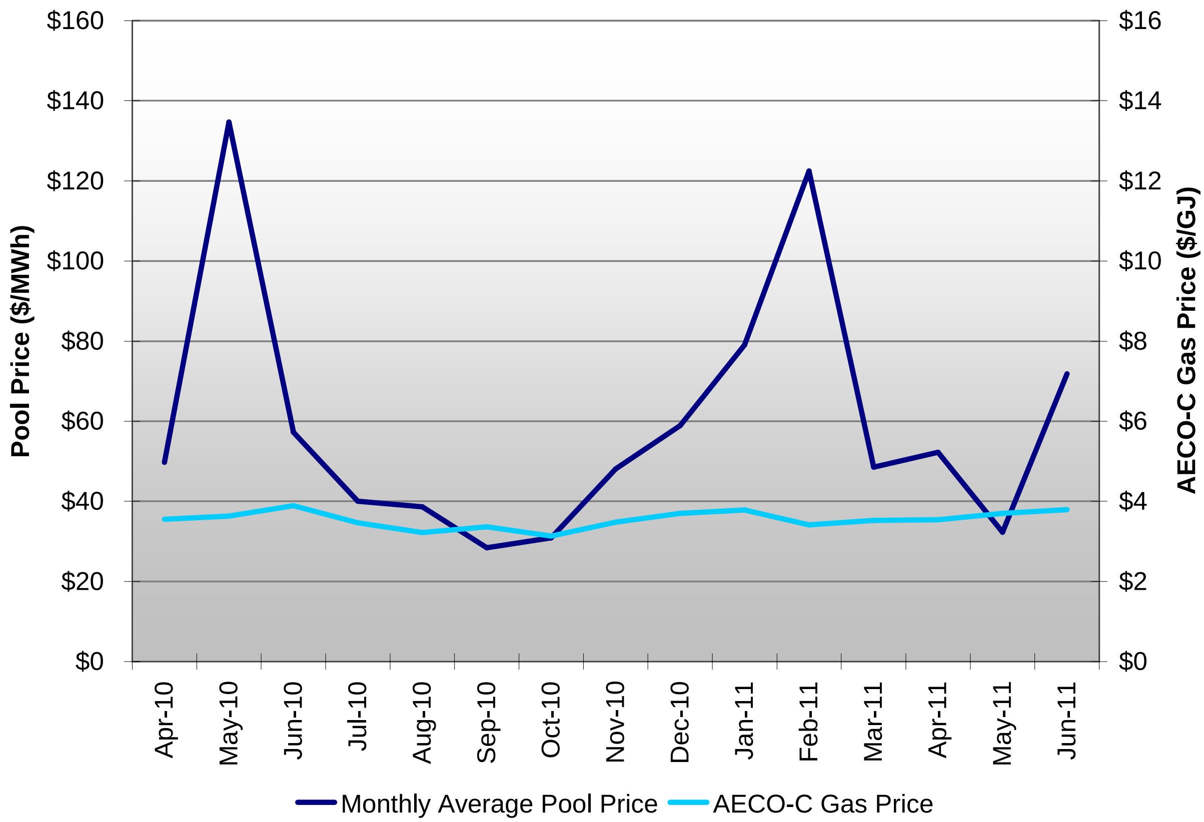


Figure A.2: Pool Price and AECO Gas Price

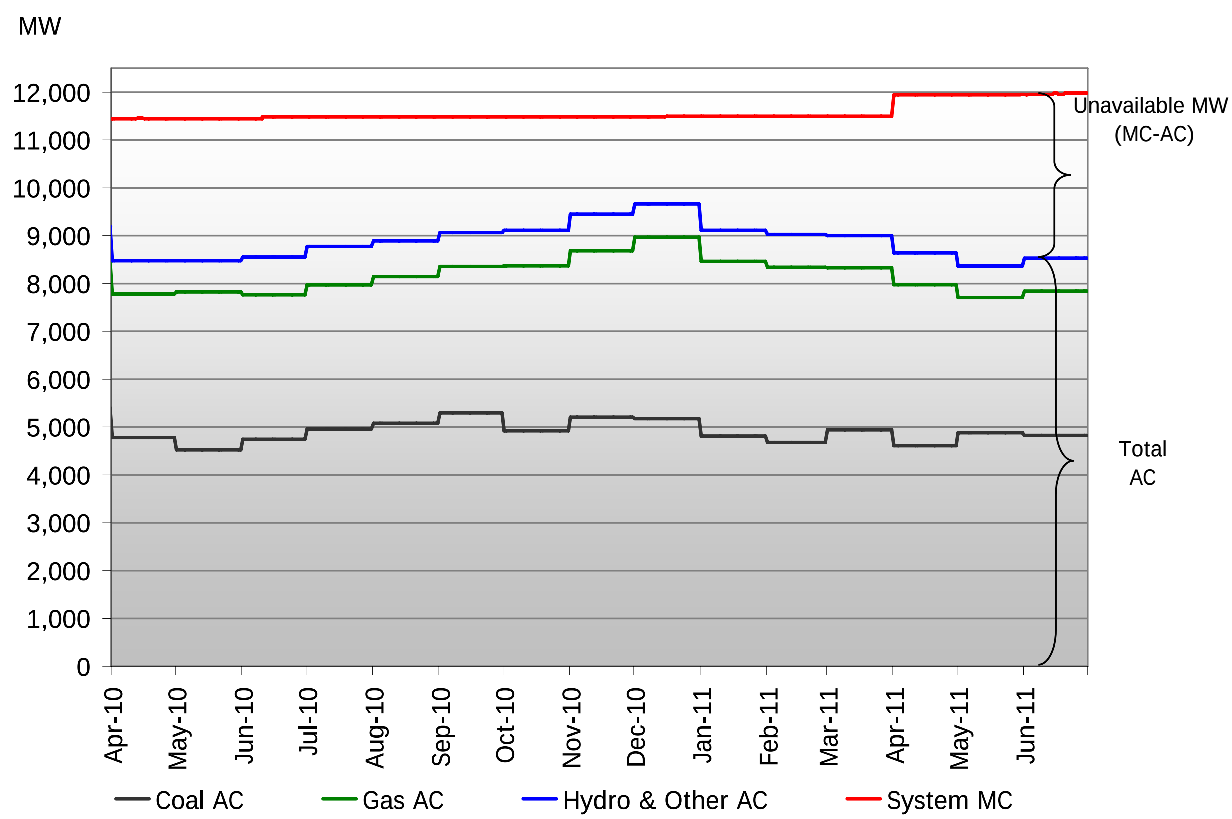


Appendix B: Supply Availability Metrics

Table B.1: Availability and Capacity Factors

Fuel Type	Quarter	Average MC [A] (MW)	Average AC [B] MW (MW)	Availability Factor [C]=[B]/[A] (%)	Generation [D] (GWh)	Capacity Factor [E] = ([D]x1000)/([A]xhrs) (%)
All Fuels *(excl. Wind)*	Q2/11	11,952	8,512	71%	14,403	55%
	Q1/11	11,499	9,047	79%	16,186	65%
	Q2/10	11,454	8,505	74%	14,687	59%
Coal	Q2/11	6,235	4,775	77%	9,129	67%
	Q1/11	5,782	4,816	83%	9,938	80%
	Q2/10	5,782	4,682	81%	9,123	72%
Natural Gas	Q2/11	4,796	3,066	64%	4,615	44%
	Q1/11	4,800	3,562	74%	5,743	55%
	Q2/10	4,754	3,110	65%	5,097	49%
Hydro & Other	Q2/11	921	671	73%	659	33%
	Q1/11	917	668	73%	505	25%
	Q2/10	917	712	78%	467	23%
Wind	Q2/11	817	n/a	n/a	534	30%
	Q1/11	762	n/a	n/a	424	26%
	Q2/10	629	n/a	n/a	349	25%

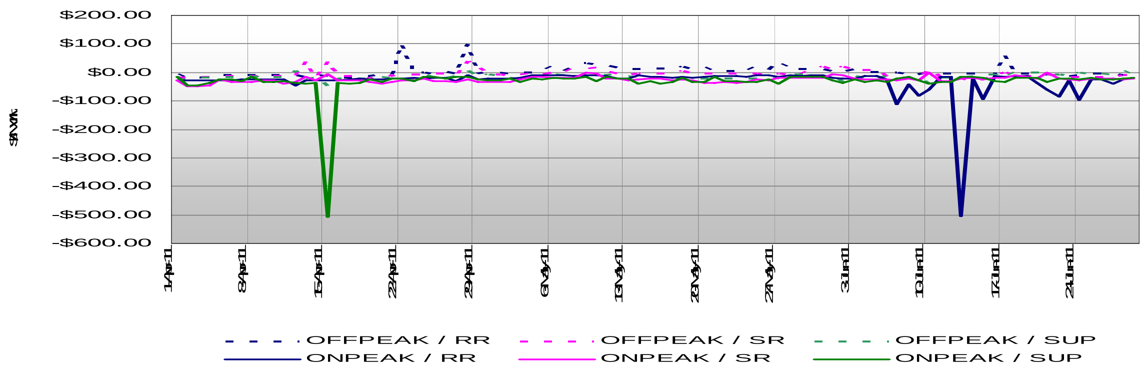
Figure B.1: Available Capacity (AC) vs Maximum Capacity (MC)



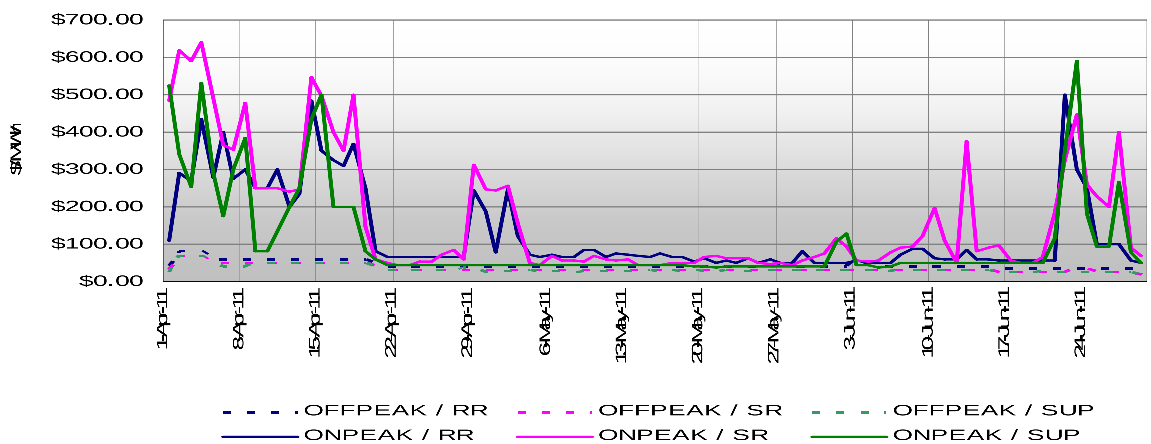
Appendix C: Operating Reserves Market Metrics

Figure C.1: Active Reserves Weighted Average Trade Index and Standby Reserve Prices

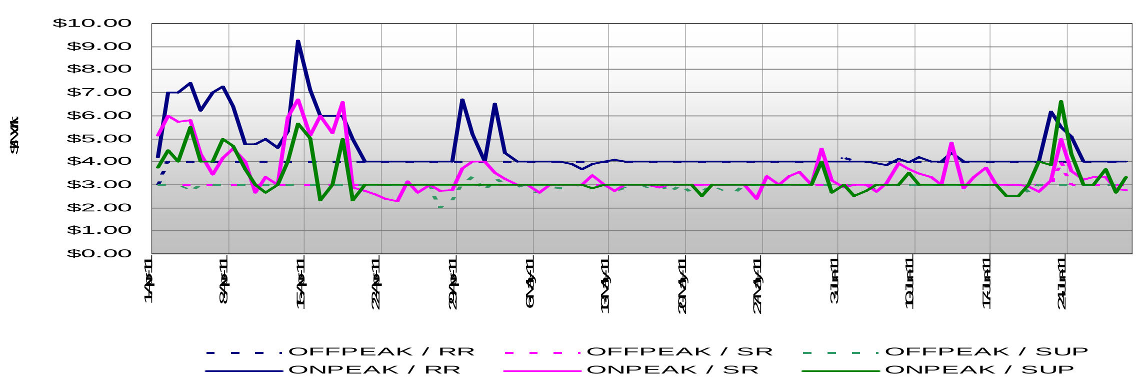
NGX Active Reserves Weighted Trade Index



Standby Reserves Average Premium Price



Standby Reserves Average Activation Price



Appendix D: Intertie Metrics

Figure D.1: Intertie Utilization – Q2/11

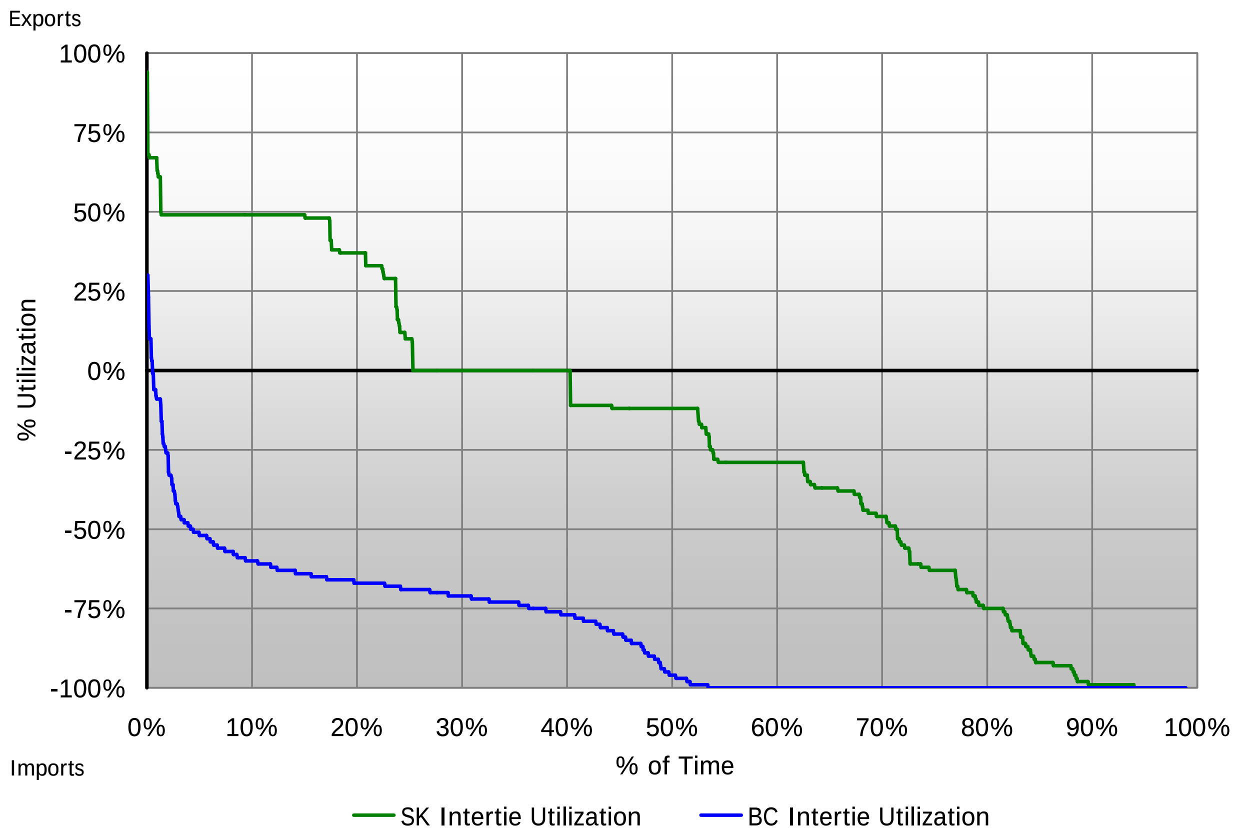


Figure D.2: On-Peak Prices in Neighbouring Markets

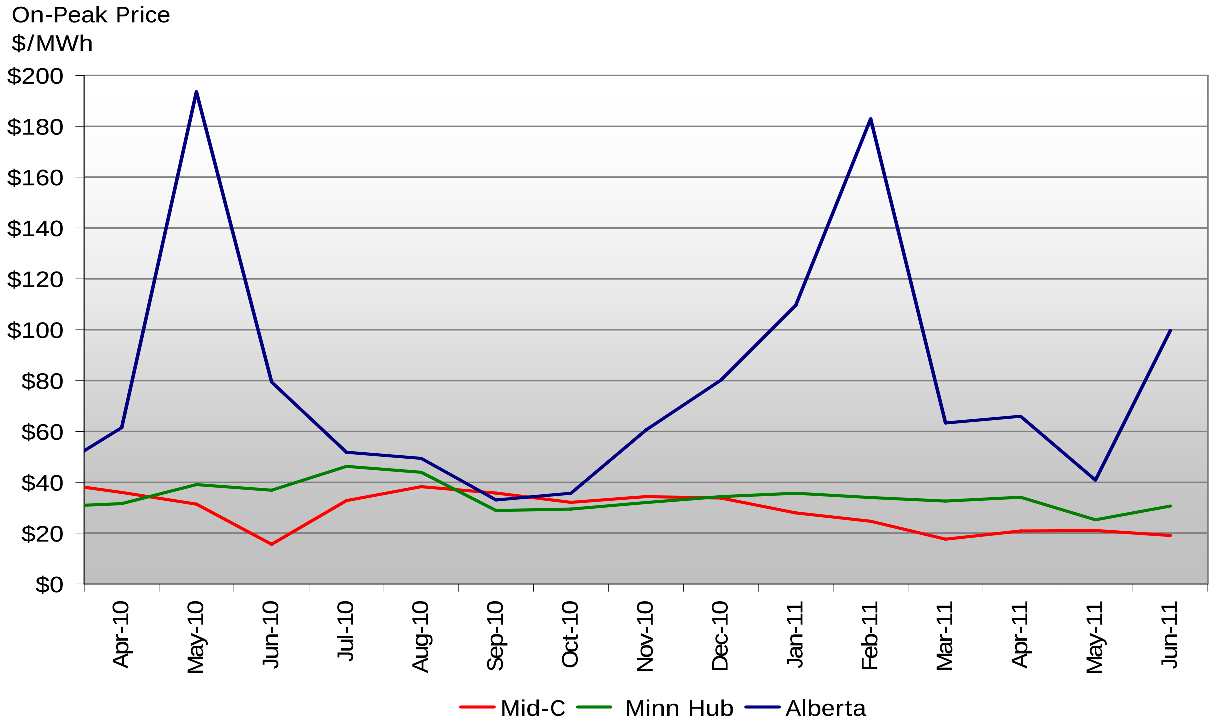


Figure D.3: Off-Peak Prices in Neighbouring Markets

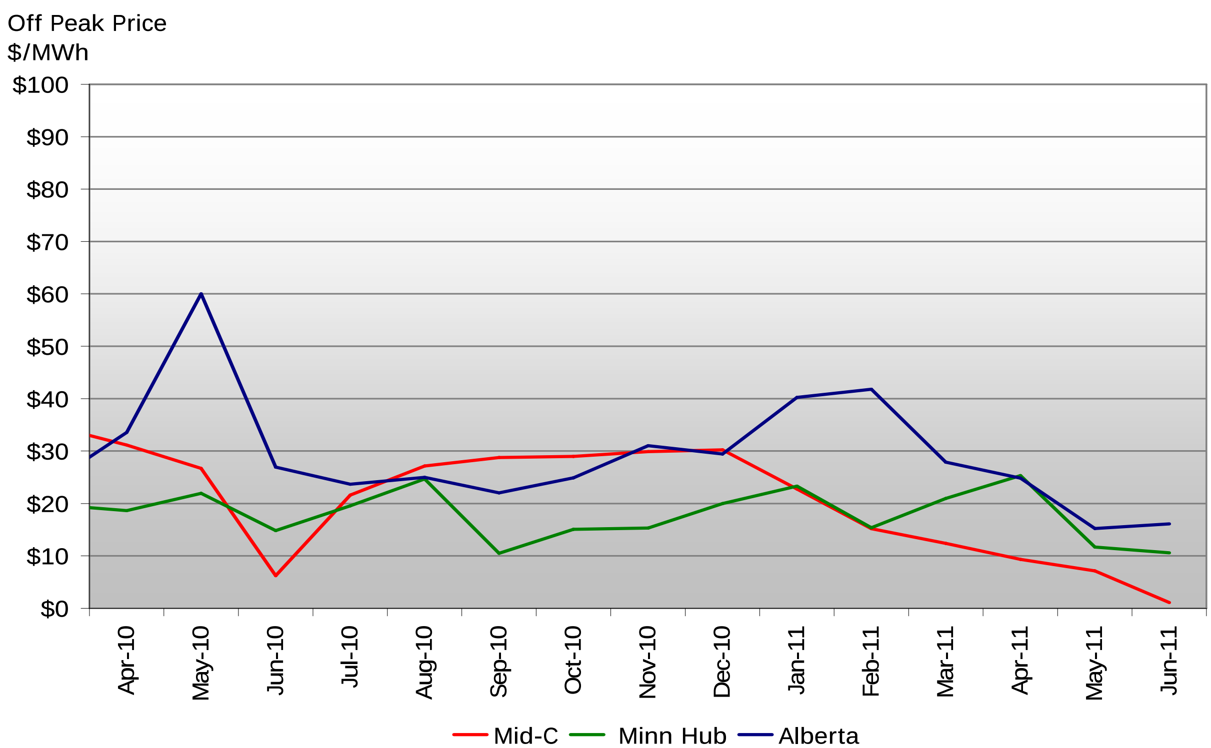
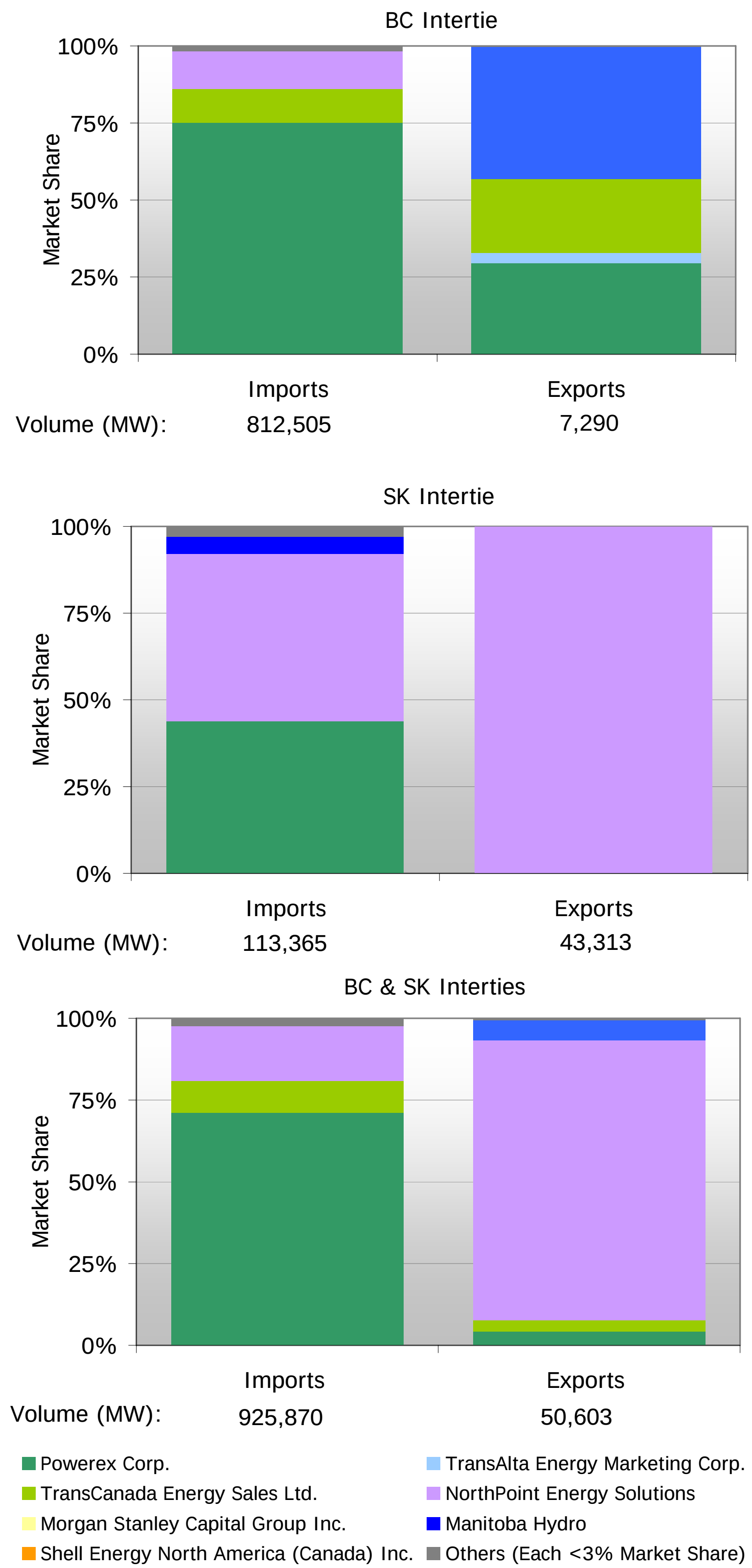


Figure D.4: Intertie Market Shares – Q2/11



Appendix E: Forward Market Metrics

Figure E.1: Volume by Trading Month

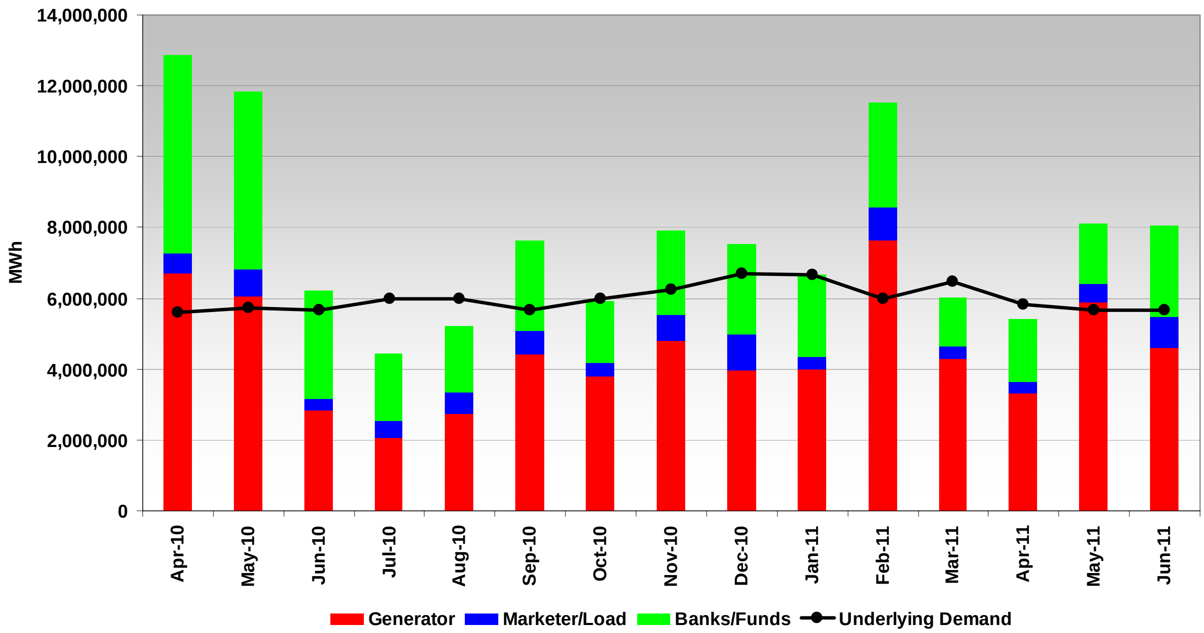


Figure E.2: Market Shares by Participant Type

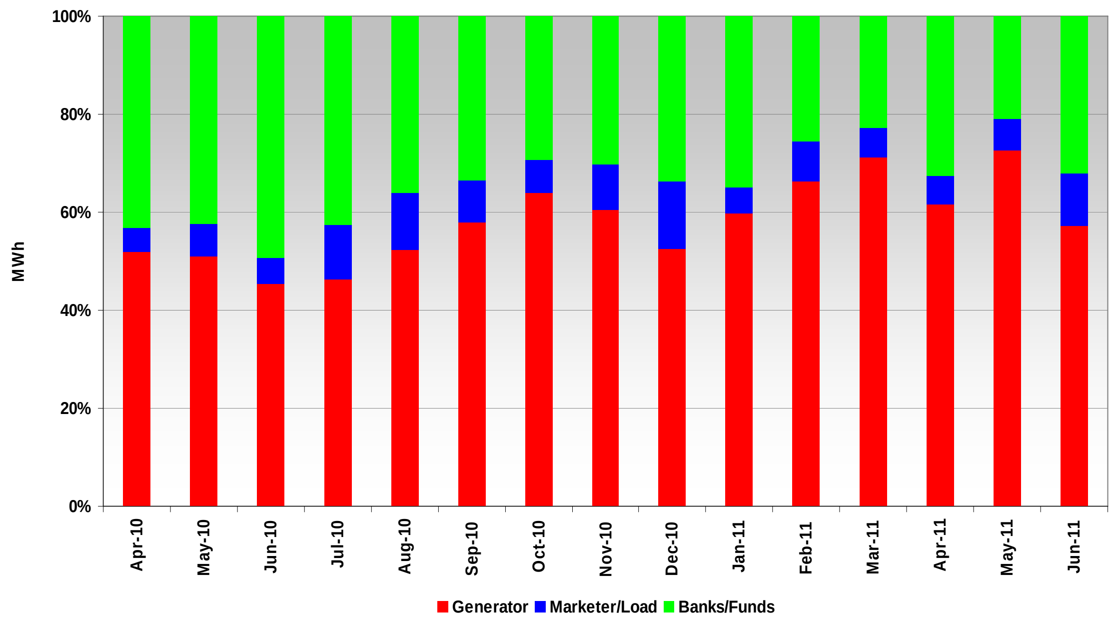
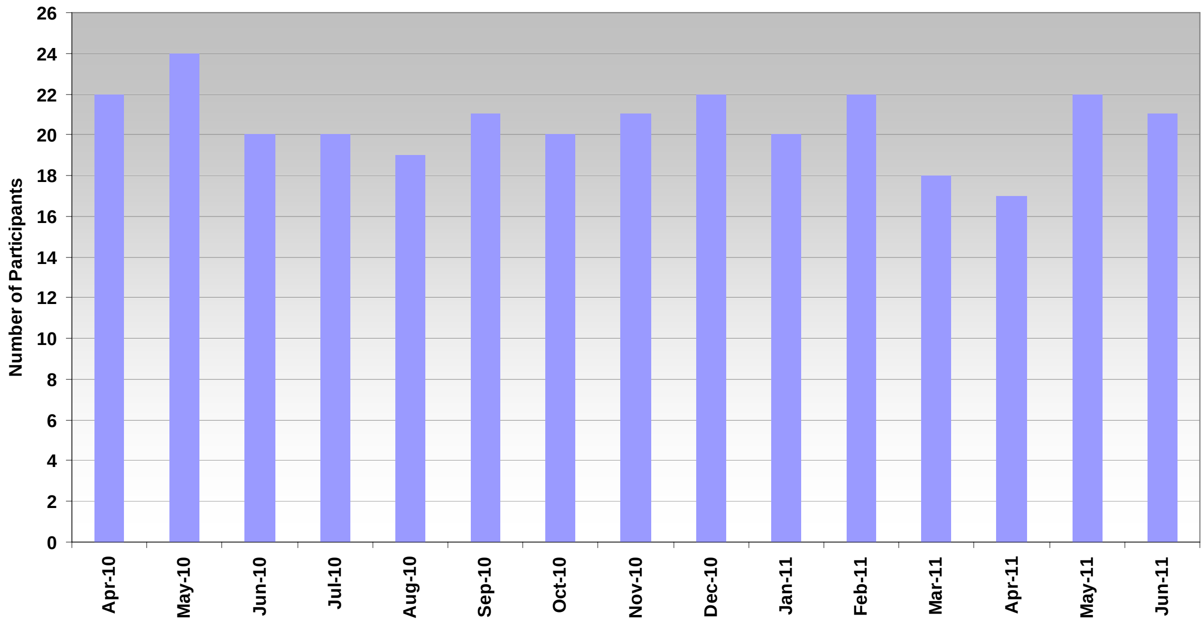


Figure E-3: Number of Active Market Participants



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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.