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MSA Report

Quarterly Report

April - June, 2009

30 July, 2009

Market Surveillance Administrator

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1 WHOLESALE MARKET

1.1 Wholesale Market Fundamentals

Q2/09 electricity prices in Alberta and surrounding markets continued the downward trend started at the onset of 2009 (Figure 14 and Figure 15 in Appendix C). The average Pool price of the second quarter of 2009 was $32.30/MWh, the lowest level in 9 years (Table i). This is 49% lower than Q1/09 and 70% below that of Q2/08 (Table 1 in Appendix A). Operating reserve prices are indexed to Pool price and, accordingly, softer Pool prices led to lower prices for operating reserves (Figure 16 in Appendix D).

Table i: Ranked Q2 Average Pool prices (2001-2009)

Year	Q2 Average Price ($/MWh)
2009	**32.30**
2002	45.03
2007	49.95
2003	50.94
2005	51.44
2006	53.62
2004	60.21
2001	88.90
2008	107.52

The volatility of Pool price was also lower in Q2/09 due to significantly less frequent price spikes (Figure 1 in Appendix A). As shown in Table ii, only 0.3% of the hours in Q2/09 were above $500/MWh, compared with 2% in Q1/09 and 3% in Q2/08.

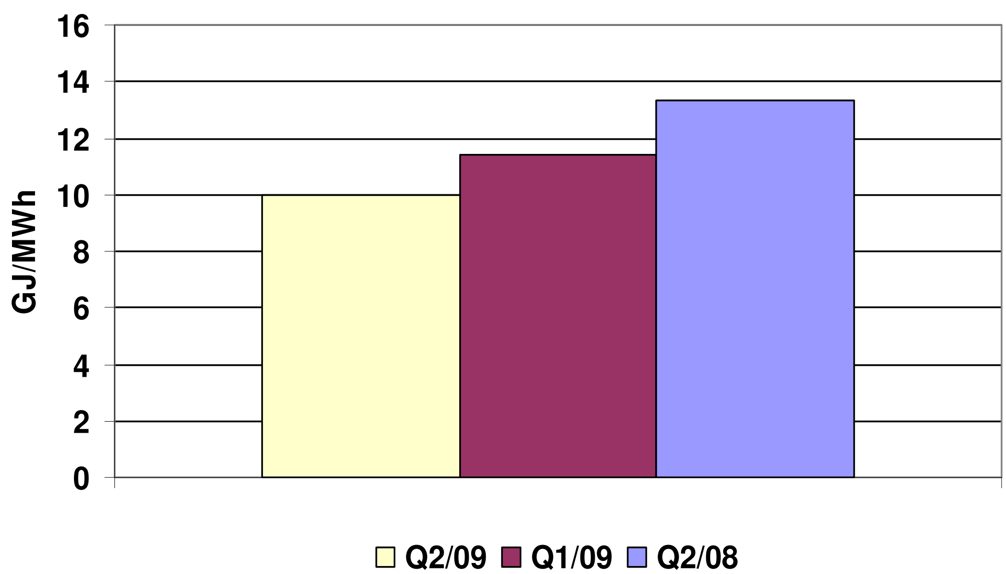
Table ii: Frequency of Different Price Levels

Pool price	Q2/09	Q1/09	Q2/08
>$500/MWh	0.1%	2%	3%
>$100/MWh	1%	5%	27%
>$50/MWh	9%	37%	71%
<=$50/MWh	91%	63%	29%

AECO natural gas prices continued to slide (Figure 3 in Appendix A) and averaged $3.27/GJ in Q2/09. This is 30% lower than Q1/09 and 66% lower than Q2/08. Lower natural gas prices contributed to lower Pool prices by enabling gas units to offer more competitively with coal units. Lower natural gas prices also have a secondary impact through the lower Reference price (based on 12.5 times the natural gas price).

The downward pressure on Pool price from previous levels also came from factors that are unrelated to natural gas prices. This is evidenced by the fact that the implied market heat rate (Pool price divided by natural gas price) in Q2/09 was lower than both Q1/09 and Q2/08 (Figure i). Interestingly, although the Pool price in Q2/09 is the lowest over the past 9 years (Table i), the implied market heat rate at 10 GJ/MWh is not low by the same standard. Compared with more recent times, the heat rate is on the low side but is the second highest Q2 heat rate since 2003. Q2/08 produced the highest Q2 market heat rate over the same period. We will now examine some of the factors contributing to softer Pool prices and heat rates in Q2/09.

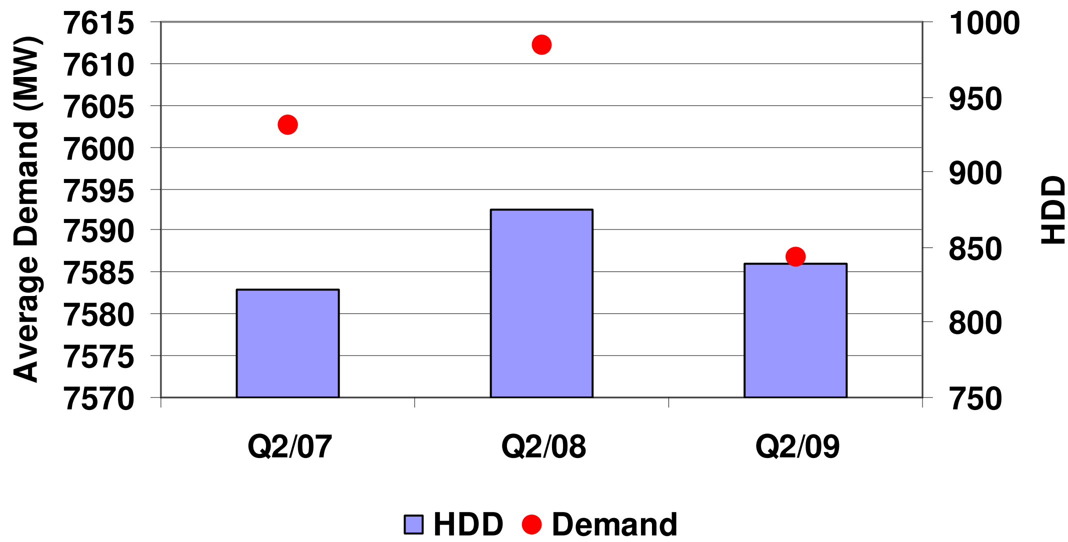
Figure i: Average Heat Rate Comparison



Demand

Demand in Q2/09 dropped by 8.9% from Q1/09 averaging 7587 MW, primarily due to warmer temperatures. The total Heating Degree Days (HDD) in Q2/09 was 840 HDD, less than half of that in Q1/09. Compared with Q2/08, demand reduced by 0.3%. Part of the reduction was due to 4% less HDD in Q2/09 than Q2/08. However, the lack of demand growth was also likely caused by the weaker performance of the broader economy. Compared with Q2/07, the HDD in Q2/09 was 2% higher but demand was -0.2% lower (Figure ii). It is interesting to note that the average demand has dropped over the past two years despite the addition of significant new oil sands developments like Long Lake.

Figure ii: Demand and Heating Degree Days



Supply Additions and Retirements

Over 500 MW of new capacity has been added since Q2/08 (Table iii). The new additions include 283 MW of co-generating units that provide on-site power to native industrial load. Since no retirements occurred in the same period, Q2/09 saw increased generating capacity compared with a year ago.

Table iii: Major New Capacity Additions since Q2/08

Project	Type	MCR (MW)	On Line Date
Long Lake	Co-Gen	180	Q2 2008
Valley View 2	Gas	47	Q2 2008
CNRL Horizon	Co-Gen	103	Q3 2008
Northern Prairie Power Project	Gas	93	Q3 2008
Clover Bar 2	Gas	101	Q2 2009

Plant Availability

The availability of generating plant, particularly the base-load coal units also has a significant effect on Pool prices. In Q2/09, the availability of the coal units averaged at 85%, up 3% and 5% from the previous quarter and Q2/08 respectively (Table 2 in Appendix B).

Imports and Exports

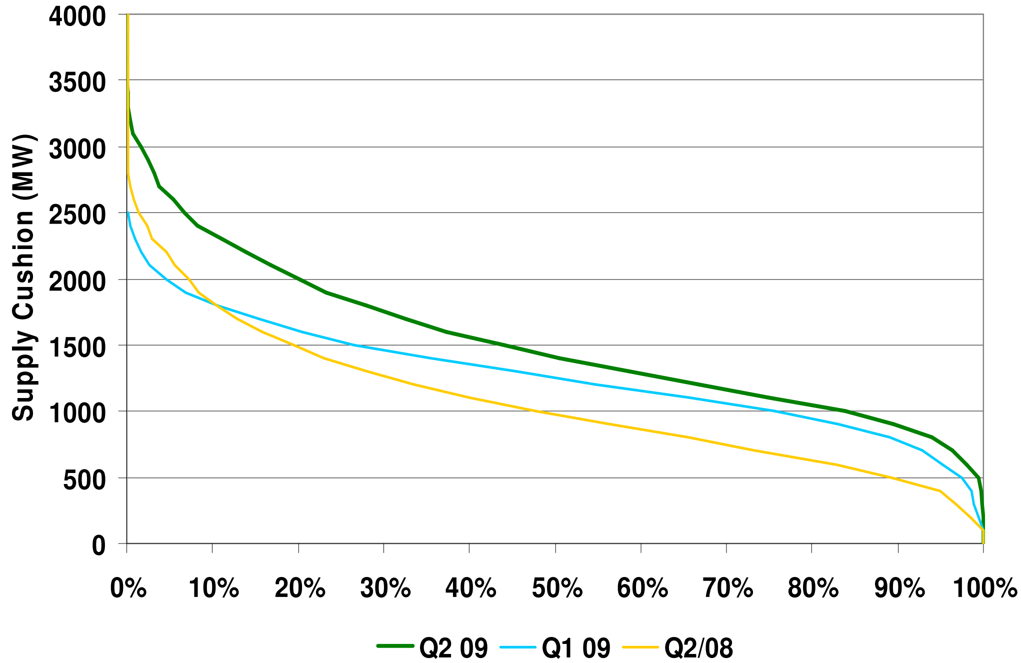
Imports to and exports from Alberta respond to market opportunities. Generally, prices in Q2/09 favoured imports, therefore, Q2/09 continued to see Alberta as a significant net importer. However, the weaker fundamentals in Alberta prevented the opportunities seen in Q1/09 and especially Q2/08 from re-occurring. Net imports in Q2/09 dropped by 32% and 42% respectively compared with Q1/09 and Q2/08, totaling at

368,000 MWh (Table 3 in Appendix C). Imports were not a primary driver of lower Pool prices in Q2/09 compared with Q1/09 and Q2/08.

Supply Cushion

The increased generating capacity and higher coal unit availability along with weaker demand strengthened the supply cushion in Q2/09. Figure iii shows the supply cushion duration curves for Q2/09, Q1/09 and Q2/08. The vertical axis indicates the amount of MWs that are out of merit in the energy merit order – the available capacity not called for by the system controller. The horizontal axis indicates how often a certain amount of MWs were out of merit. The out-of-merit MWs form the supply cushion in the energy market.

Figure iii: Supply Cushion Duration Curve



The supply cushion in Q2/09 is noticeably higher than Q1/09 and Q2/08. In the MSA's Q1/09 quarterly report, analysis demonstrated a strong relationship between Pool price and supply cushion – the nature of the relationship being that as the supply cushion decreases Pool prices tend to be higher. Typically, Pool price excursions occur when the supply cushion is very low. A closer look at the low end of the supply cushion duration curve (the right hand end of Figure iii) reveals a much lower frequency of thin supply cushion in Q2/09 than Q1/09 and Q2/08 (Table iv). The overall greater supply cushion in Q2/09 brought downward pressure on Pool prices. It is easy to see why when one contrasts on- and off-peak Pool prices. Lower demand during off-peak hours causes a reduction in the price where demand meets supply, and more surplus supply incents some generators to lower their offers to compete for sales.

Table iv: Supply Cushion

Supply Cushion	Q2/09	Q1/09	Q2/08
<200 MW	0.05%	0.5%	1.6%
<500 MW	0.6%	3%	11%
<800 MW	6%	11%	34%
<1000 MW	16%	24%	52%

1.2 The Calgary Area SVC Outage

Over the month of June, the Langdon Static VAR Compensator (SVC) was out of service (OOS). As per AESO OPP510, when this SVC is out of service, Enmax Calgary Energy Centre (CEC) must be on line if it is available. If the CEC is not on line from energy dispatch at the time of SVC OOS, a TMR dispatch will be issued to CEC. The SVC OOS in June led to a significant increase in the volume of TMR and in turn caused more MWs of Dispatch Down Service (DDS) to be utilized (Figure 27 and Figure 28 in Appendix E). The MSA has observed in the past that not all price reconstitution is 'real' as some suppliers appear to have responded to the new market (DDS) by altering their offers strategies. The effect of the changes in offer strategies is to reduce the price reconstitution[1].

1.3 Forward Trading Activity

In Q2/09, activity in the forward market held reasonably well considering the adverse economic and financial environment. The total trade volume on the Exchange (NGX) and Broker's market (OTC) in June 2009 surpassed that of a year ago[2] and the number of participants remained steady as new players joined the market replacing some that left (Figure 31 and Figure 32 in Appendix F).

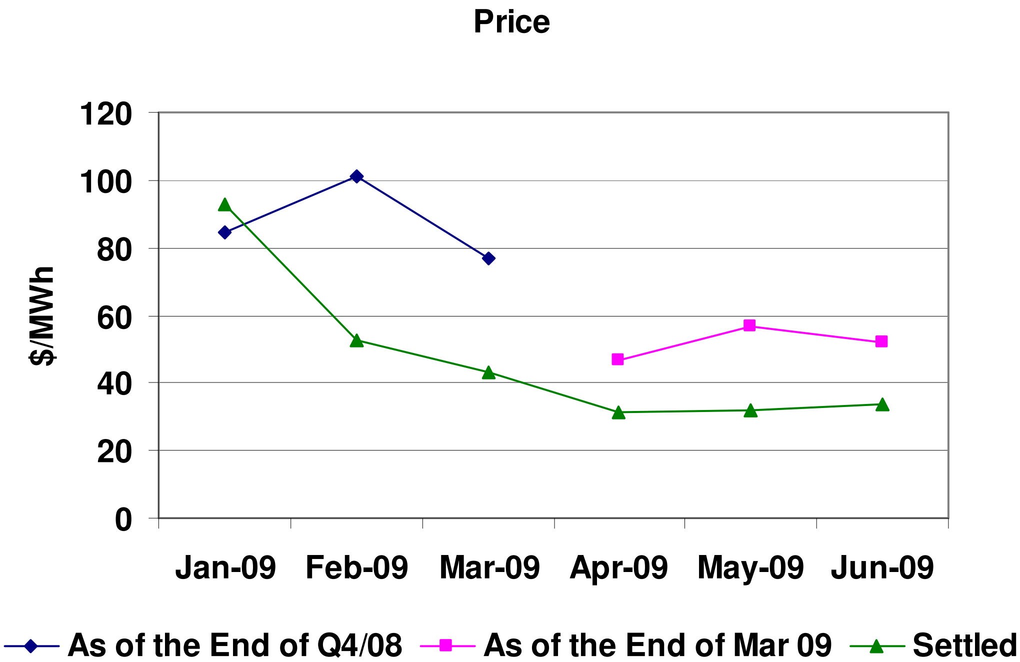
The settled Pool prices and market heat rates have been significantly lower than the forwards since February 2009 (Figure iv). Q2/09 could have been a more profitable quarter for generators who chose to sell their production forward in Q1/09.

A noticeable phenomenon is that throughout Q2/09, the near term forward market heat rate remained strong and the Alberta forward power curve remained consistently higher than the other Western Markets. The Q3/09 market heat rate as of the end of Q2/09 averaged more than 19 GJ/MWh (Figure v) and the forward curve of the *flat* Alberta contract was higher than the *on-peak* contracts in all major western trading hubs (Figure vi). Conversations with the traders suggest that greater risks were perceived in Alberta due to the volatile nature of the Pool price, and therefore greater risk premiums were added to the forward prices.

[1] http://www.albertamsa.ca/files/DDS_Report_071008(2).pdf

[2] Forward trading volumes in this report only include one side of the transactions and do not include direct bilateral volumes.

Figure iv: Forwards vs Settled Pool Price and Heat Rate



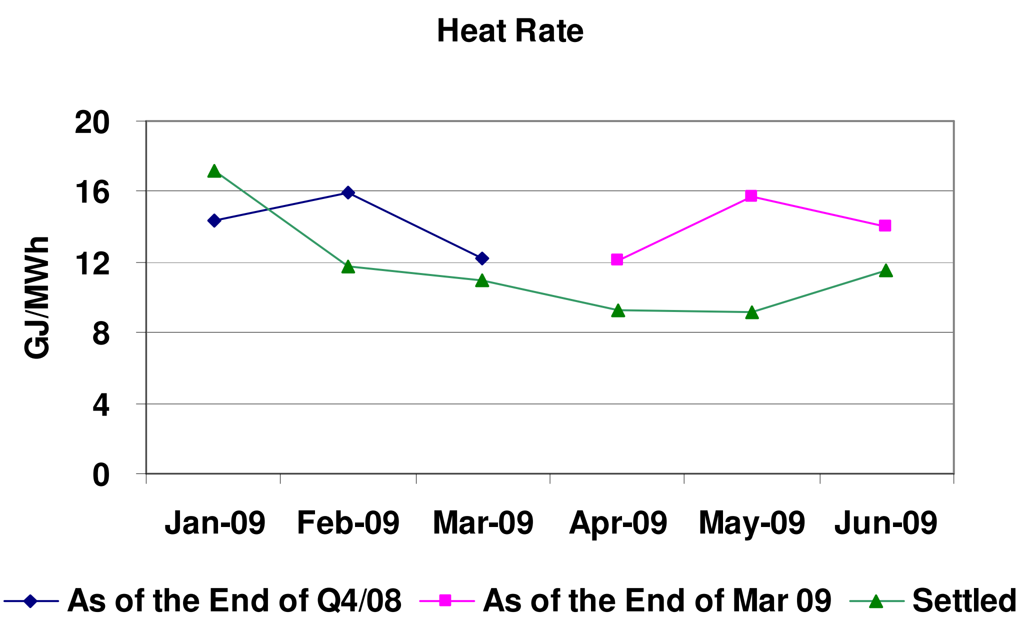


Figure v: Forward Market Heat Rate as of the End of Q2/09

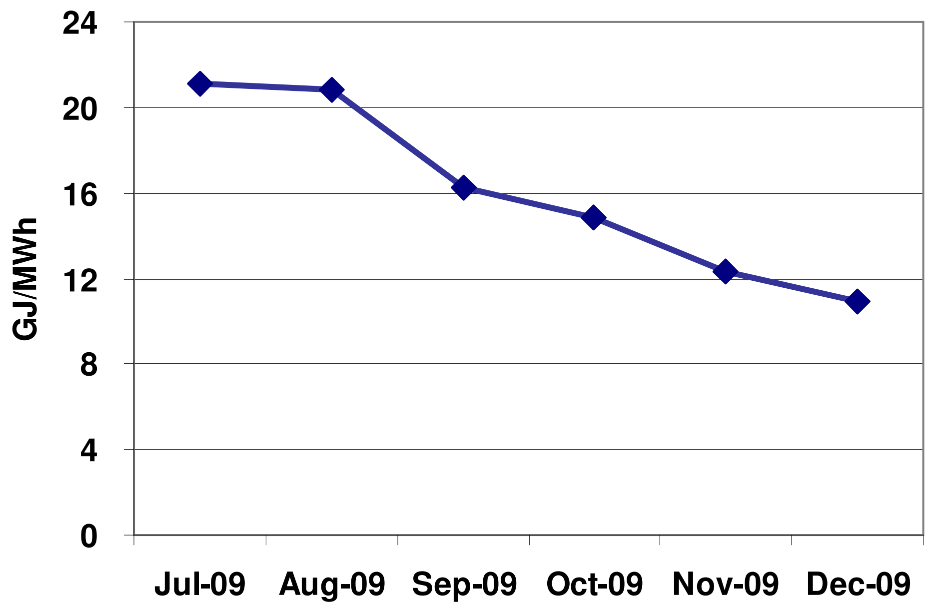
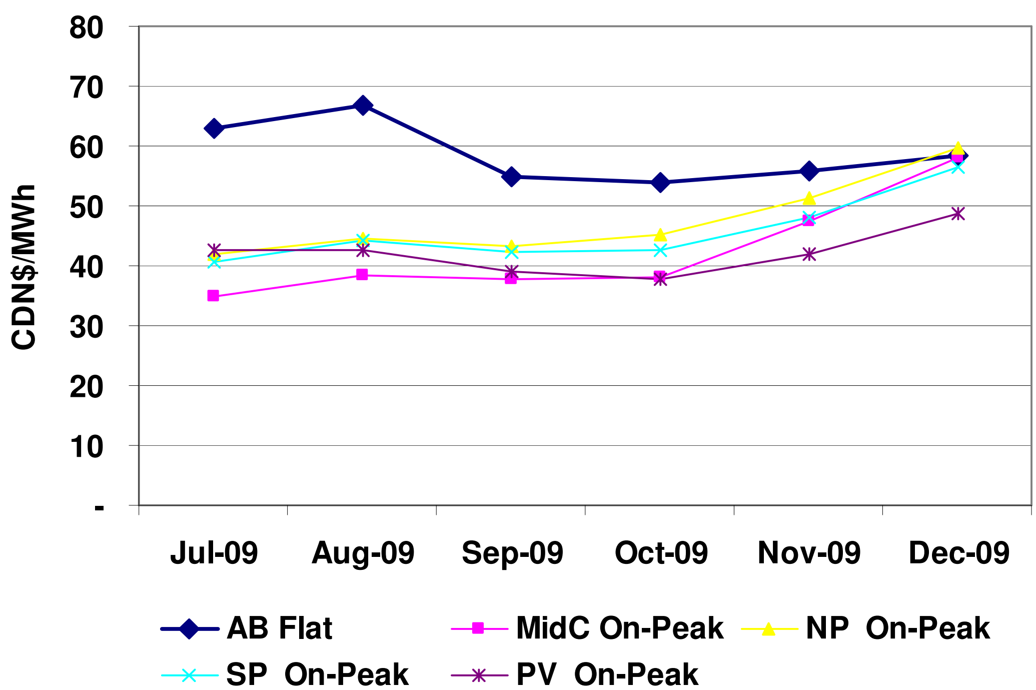


Figure vi: Forward Curves: AB Flat vs On-Peak of Other Western Markets



2 WIND GENERATION ANALYSIS

2.1 Correlation Analysis of Wind Generation

One of the issues facing wind generation in the Alberta electricity market is the tendency for many or all of the wind facilities to produce energy at the same time, leading to significant contribution of must-run energy. All else equal, this has the effect of lowering Pool price when wind facilities are generating, thereby decreasing the energy market revenue earned by the wind facilities and all other generators running at the same time.

This coincident generation across wind facilities is widely attributable to drawing from a common wind regime in the south of the province, where all existing wind facilities are located.

The following presents an analysis of the correlation[3] of average hourly wind facility output for the nine largest wind facilities in 2008[4]. The wind facilities are grouped geographically, based on the AESO's defined boundaries for South West, South Center, and South East regions[5].

Table v presents a matrix of correlation coefficients for the wind facilities of interest, as well as for total wind generation, Pool price, and demand.

Table v: Alberta Wind Farm Correlation Matrix

	South West 1	South West 2	South West 3	South West 4	South Center 1	South Center 2	South Center 3	South East 1	South East 2	Total Wind Gen	Pool Price	Demand
South West 1	1.00											
South West 2	0.84	1.00										
South West 3	0.65	0.66	1.00									
South West 4	0.82	0.74	0.73	1.00								
South Center 1	0.50	0.47	0.45	0.48	1.00							
South Center 2	0.75	0.67	0.69	0.79	0.65	1.00						
South Center 3	0.73	0.65	0.68	0.81	0.58	0.88	1.00					
South East 1	0.62	0.56	0.57	0.65	0.72	0.78	0.76	1.00				
South East 2	0.45	0.42	0.39	0.42	0.83	0.55	0.50	0.63	1.00			
Total Wind Gen	0.84	0.79	0.80	0.88	0.74	0.92	0.90	0.83	0.69	1.00		
Pool Price	-0.12	-0.13	-0.13	-0.13	-0.16	-0.15	-0.15	-0.16	-0.16	-0.17	1.00	
Demand	0.15	0.12	0.11	0.11	-0.02	0.07	0.06	0.02	-0.03	0.08	0.23	1.00

Results of the wind facility correlations show that all of the wind farms are positively correlated with one another, and a few show strong correlations. Correlations range from 0.39 to 0.88, and 27 of 36 correlations are greater than or equal to 0.5. The intra-regional correlations (within a geographical region) are not markedly stronger than the inter-regional correlations (between geographical regions).

Table v also presents the correlation of each wind facility with Pool price and with Demand. In each of these cases, the correlations are low. However, it is notable that while the correlations with Pool price are low,

[3] The correlation coefficient (ρ) is a measure of the linear relationship between two variables, bounded by -1.0 and +1.0, where ρ=0 indicates no linear relationship, while values of ρ approaching unity, either positive or negative, indicate a stronger linear relationship. The sign of the correlation coefficient indicates the direction of the relationship.

[4] For the purposes of this exercise the 15% of hours in 2008 when RAS curtailments occurred were excluded from the analysis since it is difficult to correct for the effect.

[5] As defined in the AESO's weekly Wind Power Operational and Market Reports: http://www.aeso.ca/gridoperations/14246.html

they are consistently negative. While correlation doesn't show causality, it is consistent with the hypothesis that wind generation has a depressing effect on Pool price.

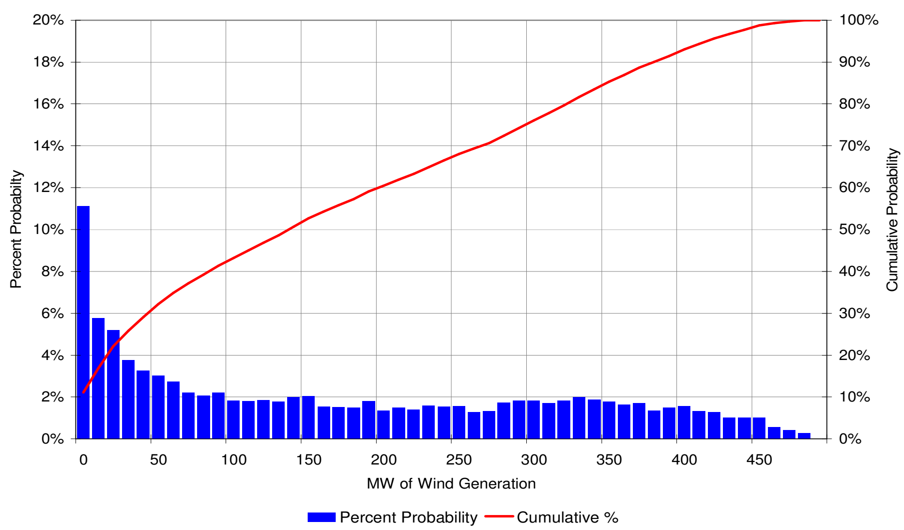
2.2 Histogram Analysis of Total Wind Generation

Another perspective on the correlation of wind facilities is presented with a histogram of total hourly wind generation, in Figure vii.

The bars plot the percent probability of total wind generation in a given hour (read from the left axis). The line plots the cumulative probability of generation being less than or equal to MW value (read from the right axis). This histogram has a strong positive skew, and takes a shape very similar to that of any of the individual wind facilities.

For comparative purposes, Figure viii presents a histogram of simulated total wind output, such that the output of individual wind farms is completely independent and uncorrelated with the other wind farms. To accomplish this simulation, the 2008 actual hourly production data for each wind farm was randomized, totaled across each hour, and then presented in histogram format. This produces a precise representation of the distribution of total wind output using the actual wind produced by each facility in 2008, and imposes total independence among the outputs of the wind facilities. The simulation is a bit extreme, as the hour to hour fluctuations in output are not realistic, and the effects of any seasonality in wind generation are completely mitigated, but the results are useful for illustrative purposes.

Figure vii: Histogram of Actual Total Wind Output



The shape of the simulated output histogram is in stark contrast to the histogram of actual output. Where the actual data produced a heavily skewed histogram, the simulation has produced a distribution with a near normal shape. The simulated histogram would further approach a normal distribution with the addition of more independent (uncorrelated) wind facilities.

Figure viii: Histogram of Simulated Total Wind Output

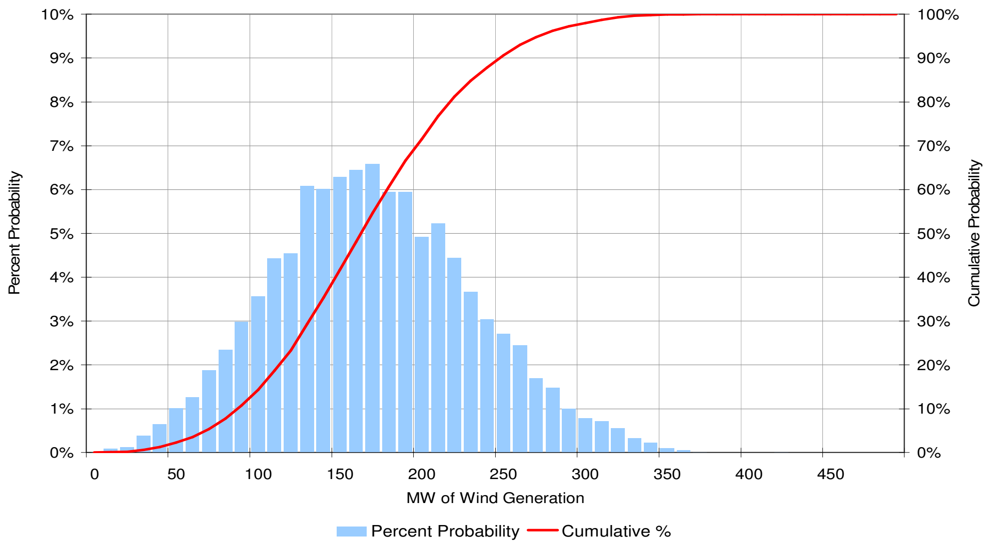


Figure ix presents the results of Figures vii and viii on the same axis for ease of comparison.

Figure ix: Comparison of Actual and Simulated Output

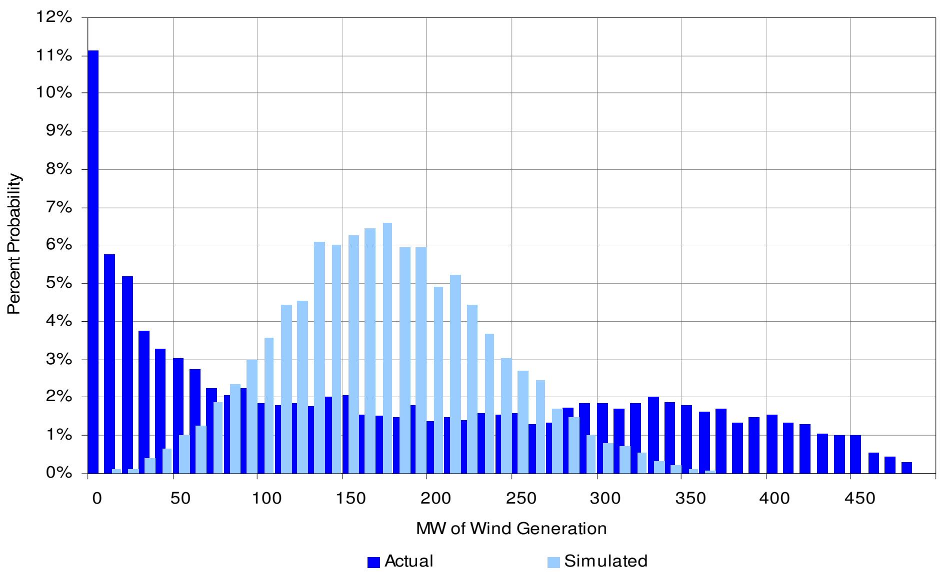


Table vi presents some descriptive statistics for the two distributions: simulated and actual. As expected the mean of both distributions is the same, however, the standard deviation of the simulated output is half that of the actual. As well, the range of output is narrower, with a higher minimum and a lower maximum.

Table vi: Histogram Descriptive Statistics

Descriptive Statistics	Simulation	Actual
Mean	176	176
Standard Deviation	61	144
Range	409	486
Minimum	12	0
Maximum	421	486

It suggests that had the production of wind farms been uncorrelated, instead of observing wind “off line” for 11% of the time, the market could have extracted “capacity value” from the existing wind facilities since between 100 MW and 250 MW would have been “on line” about 80% of the time.

2.3 Revenue Analysis

A final look at the issue of correlated wind output is taken from the perspective of the average price wind generation received through 2008. This price is calculated as the quotient of total wind revenue over total wind generation for the year.

Figure x: Wind Facility 2008 Average Revenue/MWh

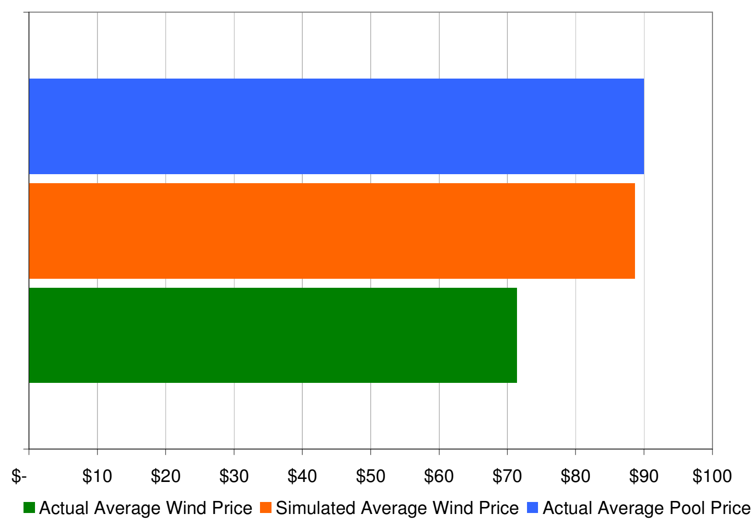


Figure x presents the actual average price wind generation earned in 2008, a simulated average price earned[6], and the actual average Pool price in 2008.

The actual average price earned by wind facilities in 2008 was $71.37/MWh, and as against, average Pool price of $89.95/MWh. The simulated price of $88.66/MWh is much closer to the actual price[7].

[6] Based on the simulation performed earlier to eliminate any correlation of wind output, and mitigate the effects of wind earning depressed Pool price.
[7] If the simulation was repeated many times the average revenue would be the actual average for 2008.

2.4 Conclusion

This analysis supports the observations by the MSA and others, that correlated wind farm output materially affects wind facility revenue and market prices for all generators. Further, the value of diversity in wind output, should it materialize in the development of new wind facilities, will be significant and beneficial both to the individual wind farms, other generators and to the system as a whole. Diversity of wind output would bring the prospect of some capacity value to wind facilities.

3 REGULATED RATE OPTION PRICE ANALYSIS

3.1 Background

According to the Electric Utilities Act, each owner of an electric distribution system is required to make available to its customers the option of being supplied electricity services under a regulated rate tariff or to purchase electricity services from a retailer. The structure of the regulated rate tariff is established in the Regulated Rate Option Regulation (AR 262/2005) that came into effect in July 2006. AR 262/2005 set out the framework by which the Regulated Rate Option (RRO) rates are to be determined. Under AR 262/2005, wire owners submit a proposed regulated rate tariff to the Alberta Utilities Commission (AUC) for approval. The proposed tariff is based on each provider's unique energy price setting plan (EPSP).

This RRO structure is a 5-year initiative (July 1, 2006 – June 30, 2011) in the interest of moving the RRO towards a "market-based" rate. RRO rates are based on a combination of monthly and long-term energy pricing, where the month-ahead component accounted for 20% of the rate basis, beginning in July 2006. In each subsequent year the month-ahead proportion increased by 20% until July 2010, when 100% of the RRO rate will be comprised of month-ahead energy pricing. As of July 2009, the RRO rates are based on an 80% month-ahead energy price.

In transitioning towards a 100% prompt month RRO rate, it is of interest to analyze the existing RRO structure. More specifically, have the changes in the RRO structure led to a reasonable representation of the market price? Also of significance is to examine the RRO rates of the principal RRO providers in Alberta (Enmax, Epcor and Direct Energy) to see whether there are significant differences amongst them.

3.2 RRO Index[8]

Monthly RRO price is a combination of the flat RRO index, extended Peak RRO index, and super peak RRO index[9]. These components account for most of the load shape of the RRO providers. Various adders are also included in monthly RRO prices that are further detailed in the RRO

[8] NGX Price Index Methodology Guide defines flat, extended peak and super peak products. See Page 22 of http://www.ngx.com/pdf/NGXPIMG.pdf

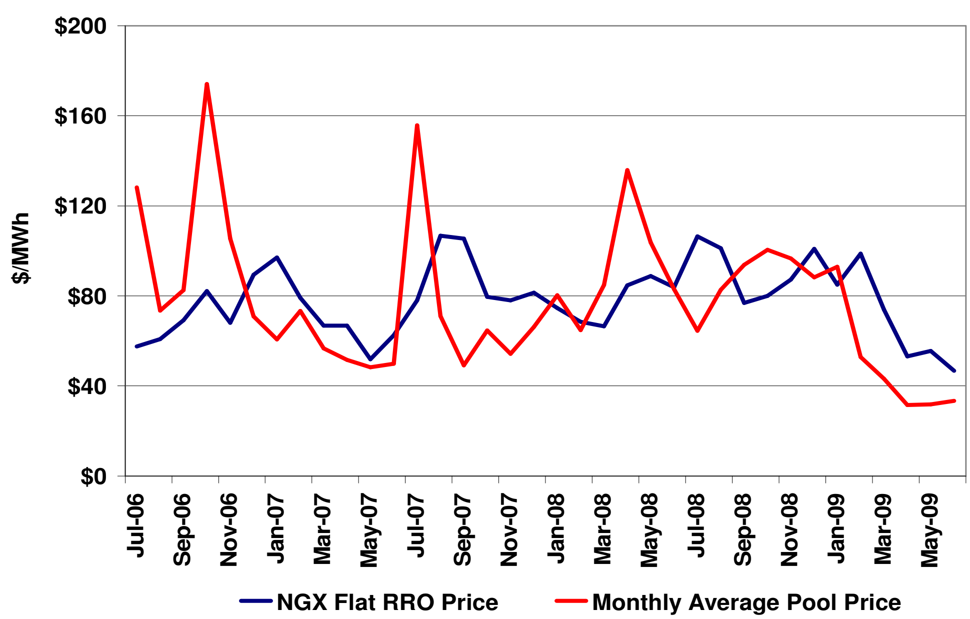
[9] Super peak RRO months are comprised of January, February, November and December.

providers EPSP. The flat RRO index is the most significant as it accounts for the largest portion of load.

RRO Index and Pool price

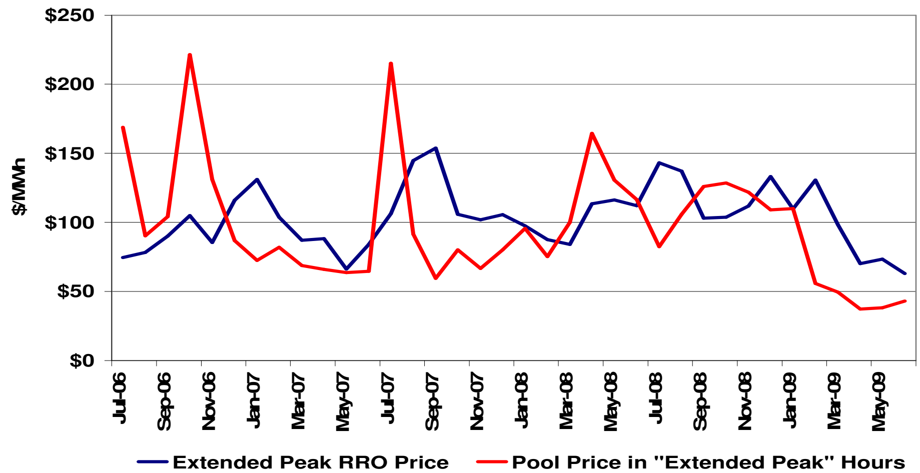
Figure xi shows the monthly flat RRO index and the average monthly Pool price. Between July 2006 and June 2009, monthly Pool price averaged $77.83 with a standard deviation of $33. The monthly RRO index averaged $78.17 with a standard deviation of $16. It is evident that the averages of the two prices are nearly equal. However the RRO index is much less volatile. The 50% reduction in standard deviation supported the prediction of the government that the RRO design would reduce electricity price fluctuations by 25% to 50% compared with Pool price flow through[10]. The trend of the RRO index seems to be that when Pool price is extremely high in a month (and not anticipated in the forward market) then for the subsequent several months the RRO index is higher than the Pool price. This suggests that the traders on the sell side price in the volatility of Pool prices. This strategy seems to work in the long term, as on average the RRO index converges with the settled Pool price. Similarly, equivalent comparisons can be drawn from Figure xii, which reflects the monthly extended peak RRO index and actual Pool prices during the "extended peak" hours (extended peak settles).

Figure xi: Monthly Flat RRO Index and Monthly Average Pool price



10 Albert Department of Energy, "Alberta's Electricity Policy Framework: Competitive – Reliable – Sustainable, Page 13.

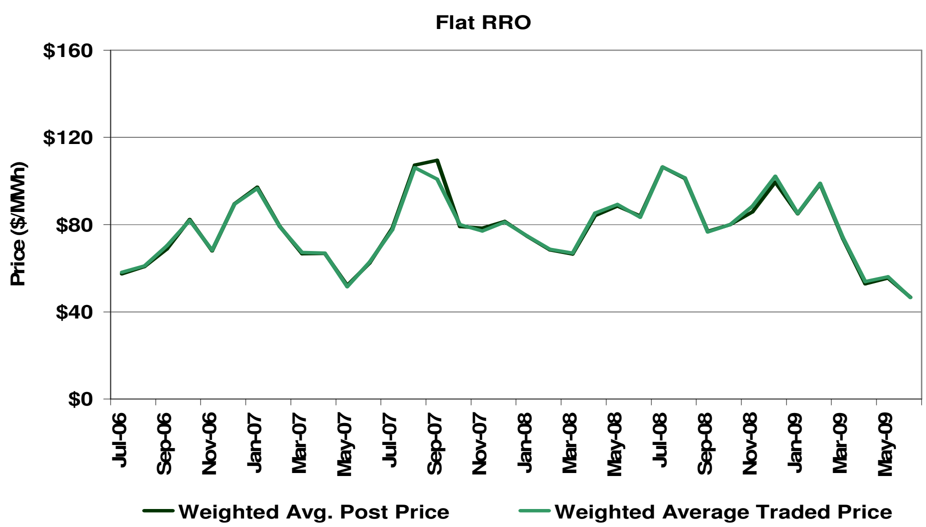
Figure xii: Monthly Extended Peak RRO Index and Monthly Average Pool Price in "Extended Peak" Hours



RRO Posted Price and Trade Price

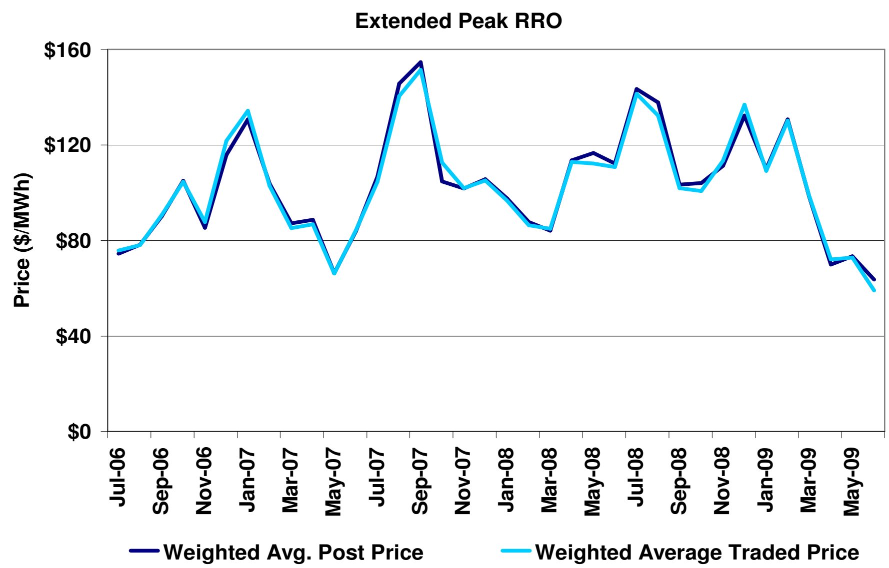
The RRO index is calculated using the volume weighted average post prices and trade prices[11]. In regards to extended peak RRO, the monthly post volumes were significantly higher than the trade volumes. Hence the extended peak RRO is more heavily weighted towards the post price. Figure xiii and Figure xiv depict the weighted average post price and the trade price for both flat RRO and extended peak RRO. No systematic bias exists for post price being higher than trade price, as both weighted averages are essentially equal. This indicates that higher post volumes did not undermine the ability of RRO index to reflect the market price.

Figure xiii: NGX Flat RRO Weighted Average Post and Trade Price



[11] The RRO index calculation methodology can be found at http://www.ngx.com/pdf/NGXPIMG.pdf

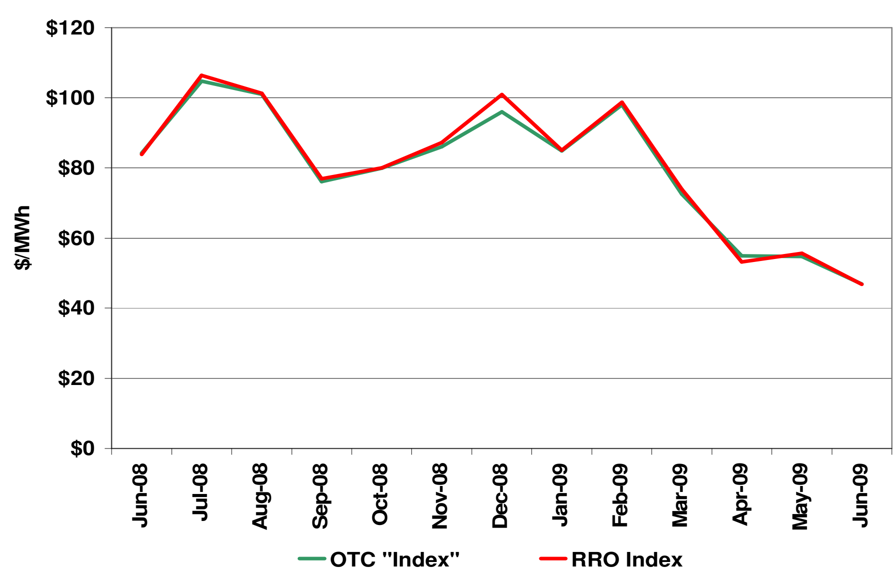
Figure xiv: NGX Extended Peak RRO Weighted Average Post and Trade Price



RRO Index and the Over-the-Counter (OTC) Price

The RRO index also tracked prices in the OTC market closely. Figure xv shows the RRO index and the OTC traded volume weighted average price on transactions within the RRO pricing window. It is evident that the RRO index strongly tracks the OTC prices. This provides confidence that the RRO indices offer a good representation of the market prices as the RRO is moving toward a regime based on 100% prompt month index pricing.

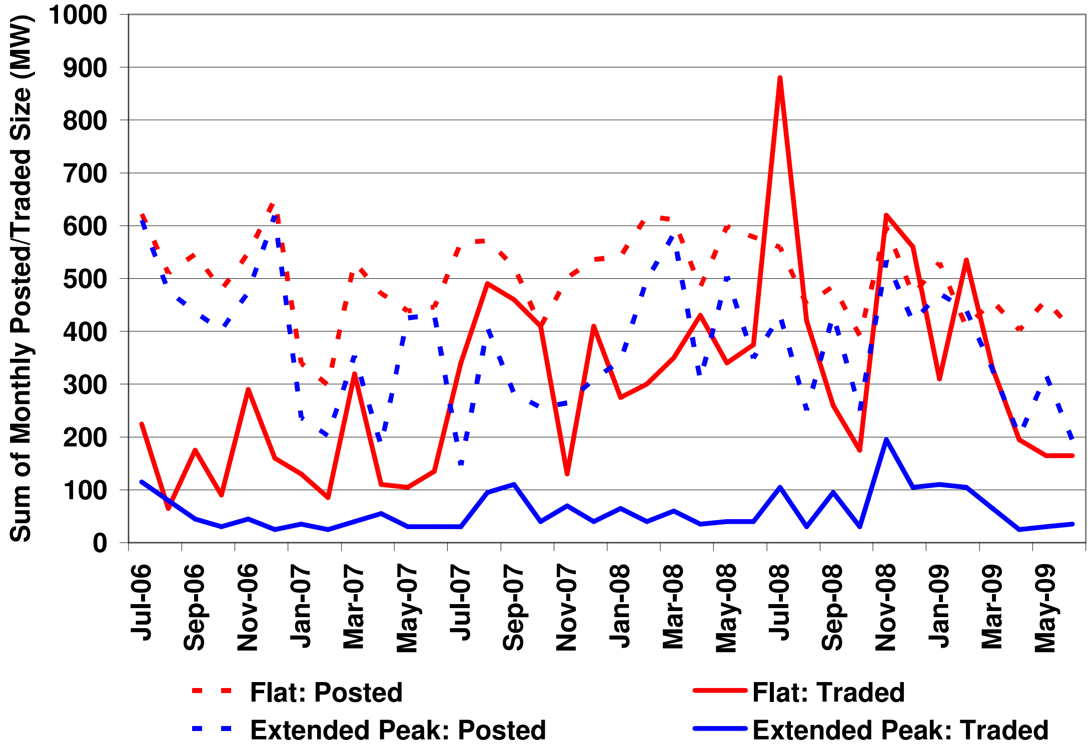
Figure xv: Flat RRO Index and the Volume Weighted Average Price of the Flat Product on OTC within the RRO Window



RRO Posted and Traded Volumes

The current RRO structure came into place 3 years ago and the Alberta market has seen growth in trade volume. Trade volumes were not robust in the early stages as there was some natural hesitation on the part of the traders to participate in this process. Figure xvi shows the total monthly contract size posted and traded on NGX for both flat RRO and extended peak RRO. The flat product trade volume has increased noticeably since the inception of the current RRO.

Figure xvi: NGX Flat RRO and Extended Peak RRO – Posted and Traded

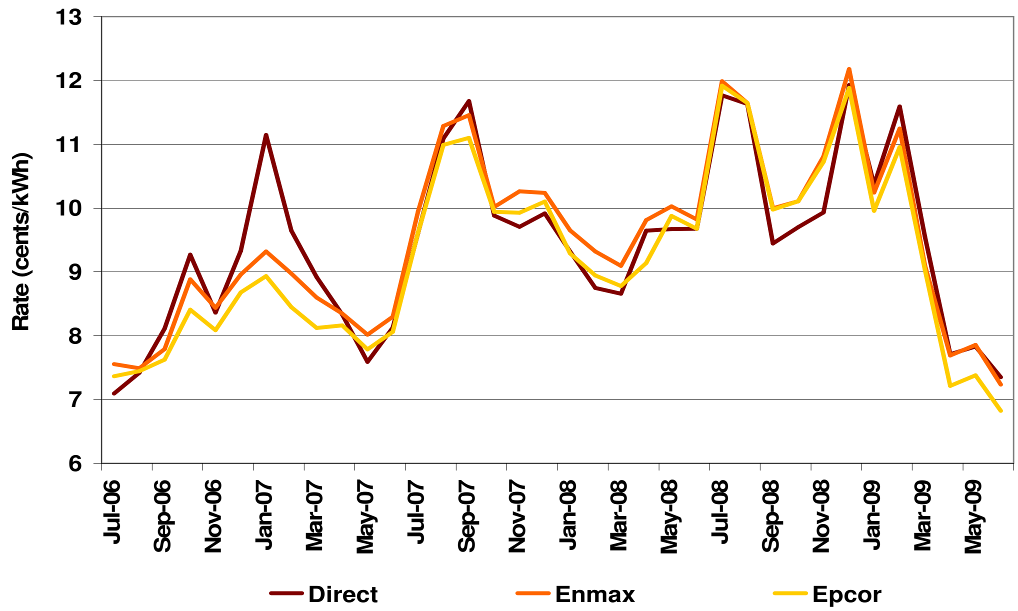


3.3 RRO Rates

The three RRO providers, Enmax, Epcor and Direct Energy have unique energy price setting plans and hence their RRO rates are not identical. Figure xvii shows the RRO rates charged by Enmax[12], Epcor and Direct Energy to their residential customers. The RRO rates from the three RRO providers have been similar, although in January 2007 Direct Energy's rate was about 2 cents/kWh higher.

[12] This is the Enmax Calgary RRO rate.

Figure xvii: The RRO Rate for Enmax, Epcor and Direct Energy



From July 2006 to June 2009 the RRO rate has averaged 9 cents/kWh for each of the providers and the standard deviation for the three retailers was also equal at 0.2 cents/kWh. There was a high correlation[13] amongst the rates of the different RRO providers.

Even though the averages amongst the three RRO providers were close, Enmax (Calgary) did have the highest residential RRO rate most often, setting the highest rate in 23 of the 36 months. Second to Enmax was Direct Energy, setting the highest rate in 12 of the 36 months. Epcor on the other hand, set the lowest monthly RRO rate in 21 of the 36 months. The range in RRO rate averaged 0.5 cents/kWh amongst the three providers, in part due to differences in load shape and procurement costs. It is important that the rates do not show marked differences as RRO customers would probably not be very happy if their rates were significantly higher than others in the province.

3.4 Conclusion

The RRO index has introduced some price volatility into RRO rates and still managed, on average, to converge with the settles. The weighted average post price and trade price for both flat RRO and extended peak RRO were virtually equal indicating no noticeable ‘walking out’ of the price. Also, looking at trading on both NGX and OTC it is clear that the RRO index tracks both markets quite well. The RRO rates charged to residential customers by the providers are very comparable. Looking forward to 2010, when 100% of the RRO will be priced based on the

[13] The correlation coefficient amongst the three providers was above 0.90, indicating a strong linear relationship.

prompt month forward price, the findings suggest that there are no apparent major concerns at the present time.

4 ISO RULES COMPLIANCE UPDATE

Table vii provides an update of the MSA's ISO rules compliance activities as of the end of Q2/09. During the first half of 2009, 16 notices of specified penalty have been issued, in 11 other instances the MSA chose to forbear, and 23 matters that have come to the attention of the MSA remained under review (compared to 12, 6 and 5 at the end of Q1/09).

Table vii: Compliance Files (as of end Q2/09)

ISO Rule	Under review	Notice of Specified Penalty	Forbearance
3.5.3	4	3	0
6.2.3	0	1	0
6.3.3	5	2	0
6.4.3	0	0	1
6.5.3	3	0	3
6.6	7	10	5
9.1.5	0	0	1
9.2	0	0	1
OPP 003.2	3	0	0
OPP 102	1	0	0
Total	23	16	11

Most of the rules in the Table vii are included in the specified penalty categories of AUC Rule 19. For these rules the MSA is granted the power and authority under Section 52 of the Alberta Utilities Commission Act (AUCA) to issue a notice of specified penalty where the MSA is satisfied that a person has contravened an ISO rule. However, some of the rules listed above do not have a specified penalty in which case the MSA may still pursue the matter of a breach of ISO rules for an administrative penalty as set out under Section 51 of the AUCA.

Appendix A of the MSA Investigation Procedures sets out an expedited process for dealing with ISO rule breaches that lead to specified penalty. For rule breaches pursued under Section 51 the MSA has thus far followed an expanded process. The MSA is not intending to incorporate this expanded process into its investigation procedures since, as indicated in the Q1/09 report, it is the MSA's intention to request that the AUC revisit Rule 19 to either expand the number of rules included in or to create a category for all rules not included elsewhere. In the interim, the expanded process includes an opportunity for the participant under investigation to comment on the process.

Market participants should also be aware that in some circumstances the MSA may choose to pursue a matter for an administrative penalty even where a specified penalty exists. These circumstances would include: instances where a large number of breaches have occurred, instances where the market participant derived economic gain, and/ or instances where material harm was caused to other market participants. If the MSA believes a matter needs to be resolved through an administrative penalty rather than a specified penalty it will endeavor to communicate this to the participant as soon as that determination is made. In the majority of cases the MSA intends to continue using the specified penalty approach where available.

4.1 Posting of Notices of Specified Penalty After July 1, 2009

Prior to July 1, 2009, under AUC rule 19 notices of specified penalty were not made public for a first or second contravention of a rule within a rolling twelve month period unless the participant failed to pay or disputed the notice. All notices of specified penalty issued after July 1, 2009 will be posted to the MSA website 30 days after the notice is issued. Note that this is contrary to the July 10, 2009 notice published to the MSA's website but follows direction contained in AUC Bulletin 2009-17, dated July 21, 2009.

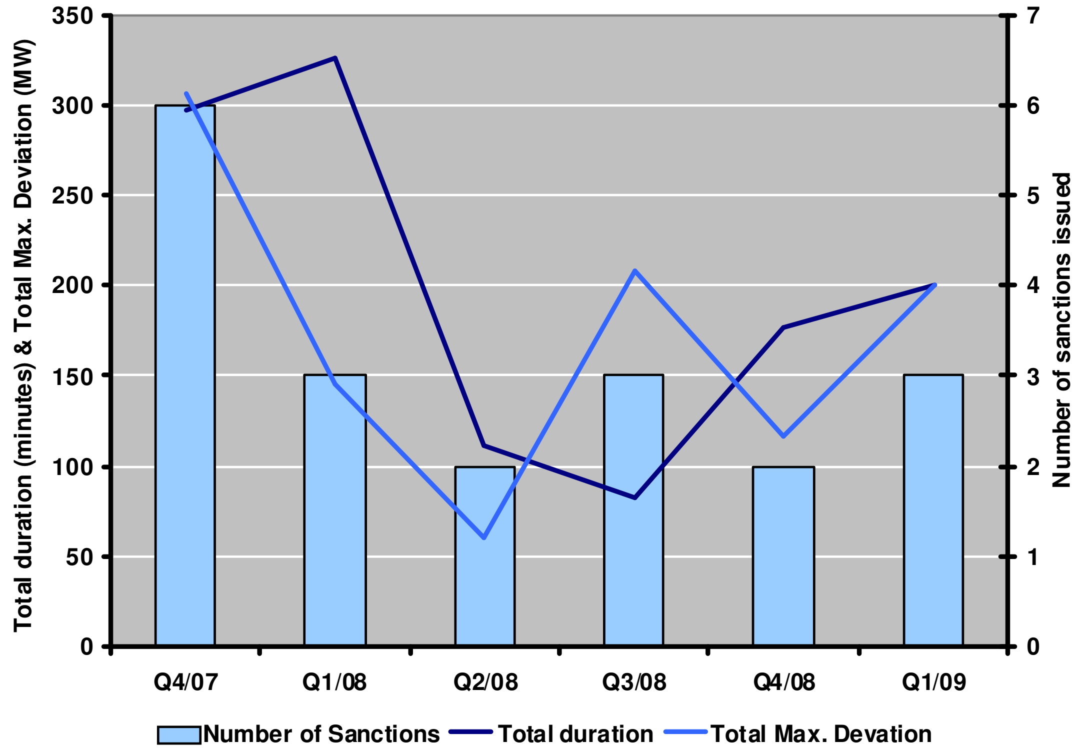
4.2 Emerging non-Compliance Trends

In Q1/09 the MSA reported on some emerging trends in potential non-compliance. Informal feedback from market participants has indicated this is useful. Based on a review of Q2/09, the MSA notes that no new areas of concern have emerged. However, the MSA would re-iterate its recommendation that market participants review their compliance activities with respect to OPP 102, OPP 003.2 and ISO rule 6.3.3.

In addition, the MSA is pleased to report the number and magnitude of ISO rule 6.6 breaches detected during Q2 appears to be much reduced. The MSA believes this is largely the result of the continued efforts made by market participants in improving compliance. In Figure viii below we show quarterly data for all rule 6.6 matters that led to the MSA issuing a notice of specified penalty or other sanction.14 In the figure we show the number of penalties issued, based on the time of contravention, along with the total duration and maximum deviations of those contraventions (i.e. if there were two contraventions in a quarter for 40 and 60 minutes with maximum deviations of 100 and 30 MW, this would be shown as a total duration of 100 minutes and total max. deviation of 130MW).

[14] Prior to July 1, 2008 the penalty included three types of sanction: a warning letter, a letter of non-compliance and administrative penalty.

Figure xviii: Rule 6.6 Non-Compliance Events (Q4/07 – Q1/09)



Note that neither Q4/07 nor Q1/09 includes a full quarter of data. In the case of Q4/07 some matters were dealt with by the AESO. For Q1/09 a number of matters are currently under review that may or may not lead to the issuance of a notice of specified penalty. While no exactly comparable data exists for the rest of 2007, the AESO's compliance monitoring report for events arising in 2007 lists 31 contraventions of ISO rule 6.6[15] or approximately 9 per quarter (including the 6 events pursued by the MSA for Q4/07). Compared with the quarterly estimated for 2007, the 2008 average of 2.5 events per quarter shows a marked improvement.

The MSA would also note that should the revised version of AESO rule 6.6 be approved by the AUC, it is the market participants' responsibility to ensure they are fully compliant with the new rule on the effective date, currently proposed as September 1, 2009.[16]

[15] http://www.aeso.ca/downloads/CM_Report_2007_Report_Update_Final.pdf
[16] http://www.aeso.ca/downloads/Notice_of_Filing_Final_Proposed_Level_I.pdf

5 MSA ACTIVITIES

5.1 Stakeholder Consultation: Publication of Retail Market Statistics

On June 11, 2009 the MSA commenced a stakeholder consultation regarding the publication of retail statistics, noting that data and statistics are far more readily available for the wholesale electricity market as compared with retail electricity and natural gas markets. Comments on the initial 'Strawdog' were received from three market participants. A draft proposal was posted to the MSA's website in mid-July, with comments due by July 31, 2009. The process is set to conclude by mid August. For further details see http://www.albertamsa.ca/files/Retail_Stats_Strawdog_061109(2).pdf.

5.2 Fair, Efficient and Open Competition Regulation

Following the release of the Fair, Efficient and Open Competition Regulation the MSA posted a number of notices to its website, these are:

- **Notice Re: Market Share Offer Control Process (July 13, 2009)** – This notice relates to Section 5 of the regulation that requires the MSA to publish, at least annually, certain metrics relating to market share offer control. The notice includes a 'Strawdog' that initiates a consultation on matters of process related to the collection of data required to publish the metrics. Written comments from Stakeholders are due by August 7, 2009. See http://www.albertamsa.ca/970.html for further details.
- **Notice Re: Effect of FEOC Regulation on MSA Trading Practices Guideline (July 23, 2009)** – This notice describes the effects of Section 4 of the regulation on the MSA's TPG. http://www.albertamsa.ca/files/Notice_to_Market_-_FEOC_Regulation_-_Revocation_of_TPG_-_07-23-09.pdf
- **Notice Re: FEOC Regulation – Section 3 – Preferential Sharing of Non-Public Records** – This notice discusses the effects of Section 3 of the regulation and invites affected market participants to contact the MSA for clarification. http://www.albertamsa.ca/files/Notice_to_Market_-_FEOC_Regulation_-_Info_Sharing_Requirements_-_07-22-09.pdf

5.3 MSA Email Addresses for Regular Reporting

On June 18, 2009 the MSA posted a notice indicating it had created a standard email address for market participants that regularly report data to the MSA (reporting@albertamsa.ca). The notice also reminded market participants that the MSA uses two other addresses: one for self reporting contraventions of ISO rules (compliance@albertamsa.ca); and one for receiving comments during a stakeholder consultation (stakeholderconsultation@albertamsa.ca). For further details see: http://www.albertamsa.ca/files/Notice_Re_Regular_reporting.pdf.

5.4 AUC Proceedings

During Q1/09 the MSA has been actively involved in one proceeding before the Alberta Utilities Commission:

- **Proceeding 168** - Confirmation of a Specified Penalty issued to Syncrude Canada Ltd – An oral hearing for this proceeding took place on May 27, 2009. Following the hearing, opportunity was provided for written argument and reply argument. This stage of the proceeding was completed by July 3, 2009, with a final decision from the Commission expected by early October.

The MSA also filed comments in response to AUC Bulletin 2009-15: Consultation on Market Surveillance Administrator (MSA) Proceedings before the Alberta Utilities Commission (AUC or Commission). These comments are available on the AUC's website.

5.5 Offer Behaviour Consultation

In Section 3 of Q1/09 report it was noted that the MSA was considering engaging stakeholders in a consultation to develop guidance around what is, and is not, acceptable offer behaviour in the Alberta market. During Q2/09 we have conducted a 'filtering' exercise with interested stakeholders to assist the MSA in developing a 'Strawdog' that would mark the formal start of the consultation. The MSA is currently working on the 'Strawdog' but, given we currently have two active Stakeholder consultations, does not anticipate starting the consultation before the end of summer. Until the formal start of the consultation the MSA is still open to considering ideas and suggestions of stakeholders. Should you wish to engage in this part of the work please contact Matt Ayres at 403-705-3182 or at matt.ayres@albertamsa.ca.

5.6 Appointment of a New MSA

On June 30, 2009 Martin Merritt's term of office as the Market Surveillance Administrator expired. Martin has elected not to stand for re-appointment for another term. As per section 33(5) of the Alberta Utilities Commission Act, Martin continues to hold office until a successor is appointed or a period of three months has elapsed.

APPENDIX A – WHOLESALE ENERGY MARKET METRICS

Table 1 - Pool Price Statistics

	Average Price[1]	On-Pk Price[2]	Off-Pk Price[3]	Std Dev[4]	Coeff. Variation[5]
Apr-09	31.53	38.56	21.91	35.58	113%
May-09	31.91	39.73	22.01	27.87	87%
Jun-09	33.48	45.09	17.60	43.82	131%
Q2-09	**32.30**	**41.12**	**20.54**	**36.26**	**112%**
Jan-09	92.97	116.46	60.44	157.89	170%
Feb-09	52.84	57.54	46.58	34.30	65%
Mar-09	43.21	49.83	34.78	51.45	119%
Q1-09	**63.36**	**75.60**	**47.08**	**101.67**	**160%**
Apr-08	135.95	173.08	85.15	160.99	118%
May-08	103.73	137.54	56.90	112.12	108%
Jun-08	83.00	125.96	29.31	154.18	186%
Q2-08	**107.52**	**145.68**	**56.64**	**145.31**	**135%**

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 1 – Pool Price Duration Curves

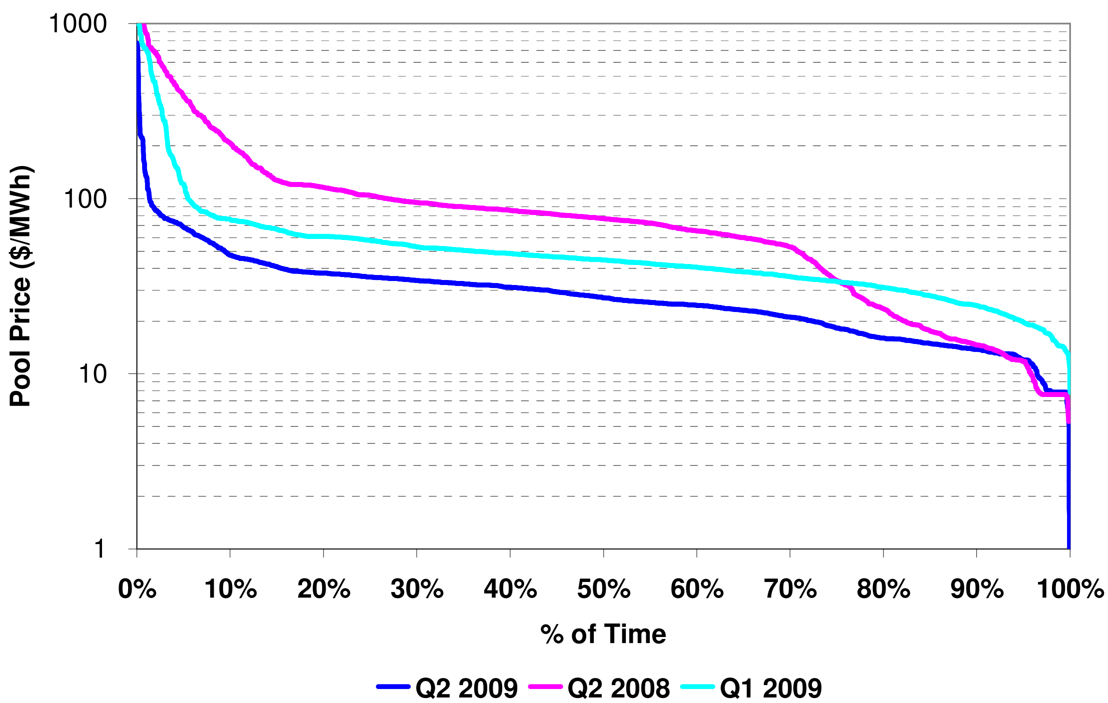


Figure 2 – Pool Price with Pool Price Volatility

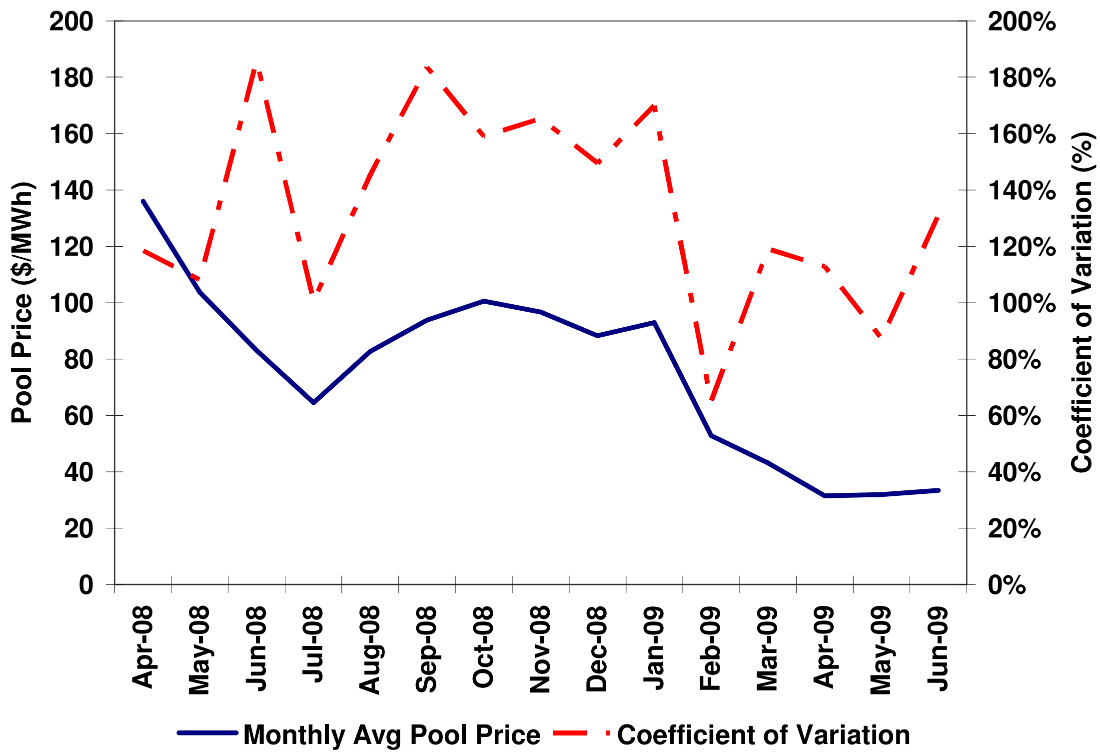


Figure 3 - Pool Price with AECO Gas Price

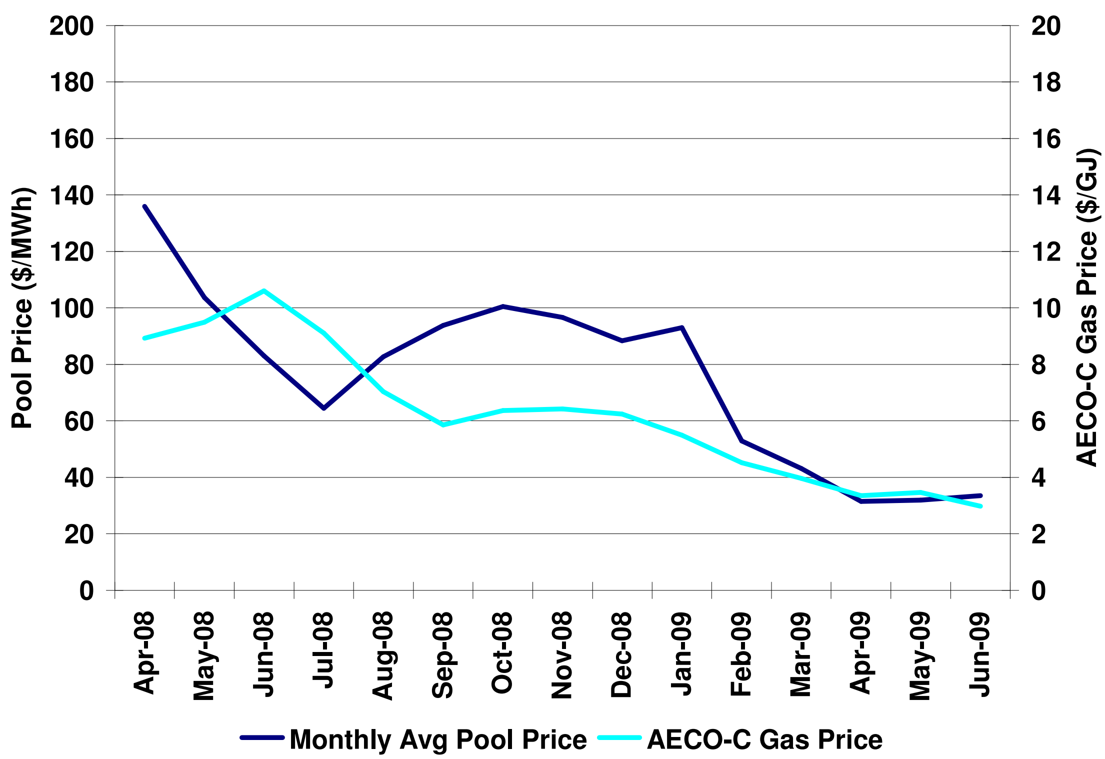


Figure 4 - Price Setters by Pool Participant (All Hours)

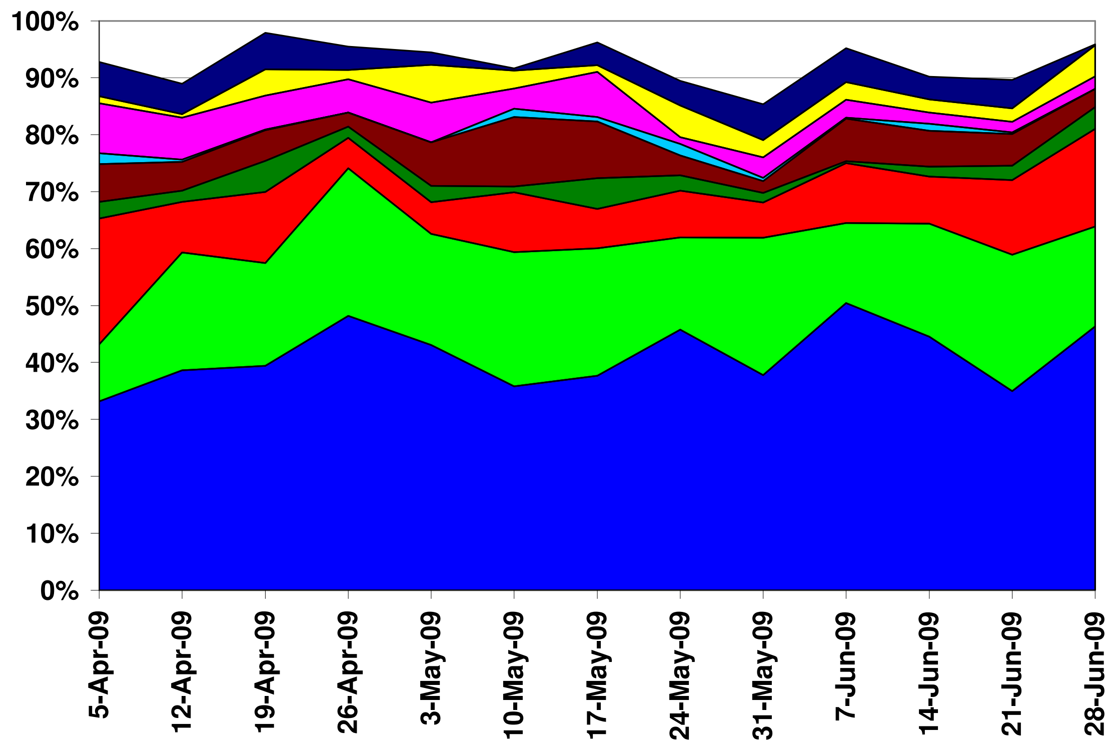


Figure 5 - Price Setters by Fuel Type (All Hours)

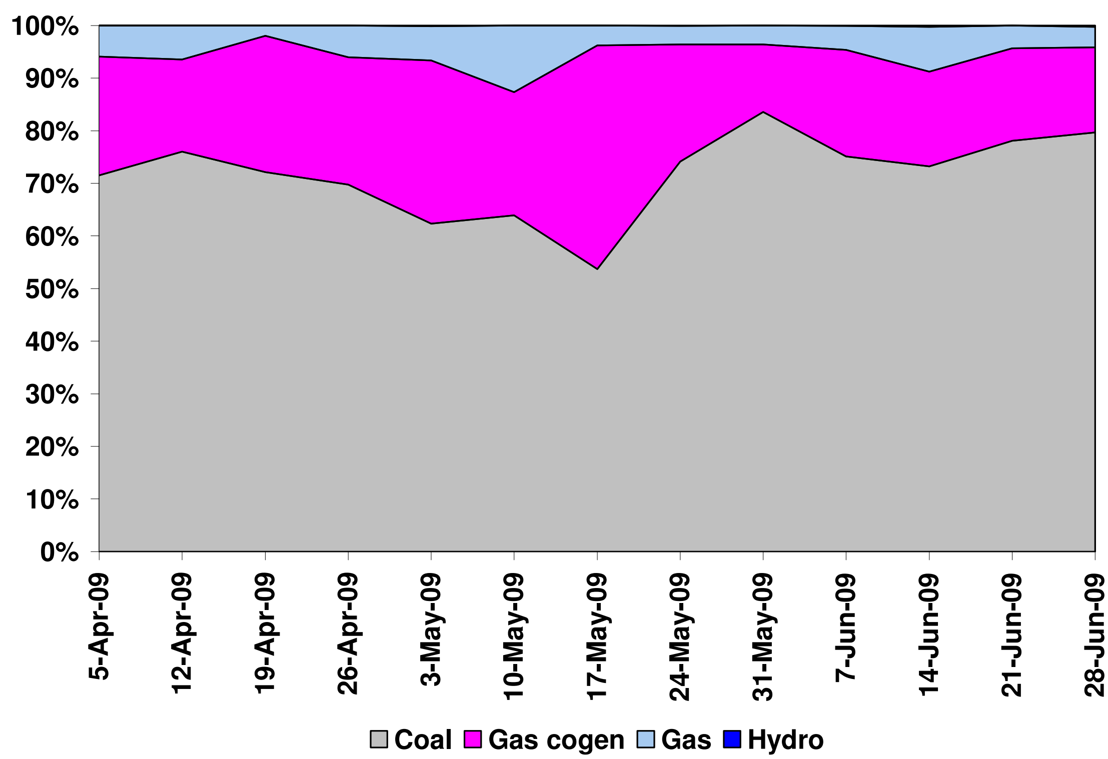


Figure 6 – Heat Rate Duration Curves (All Hours)

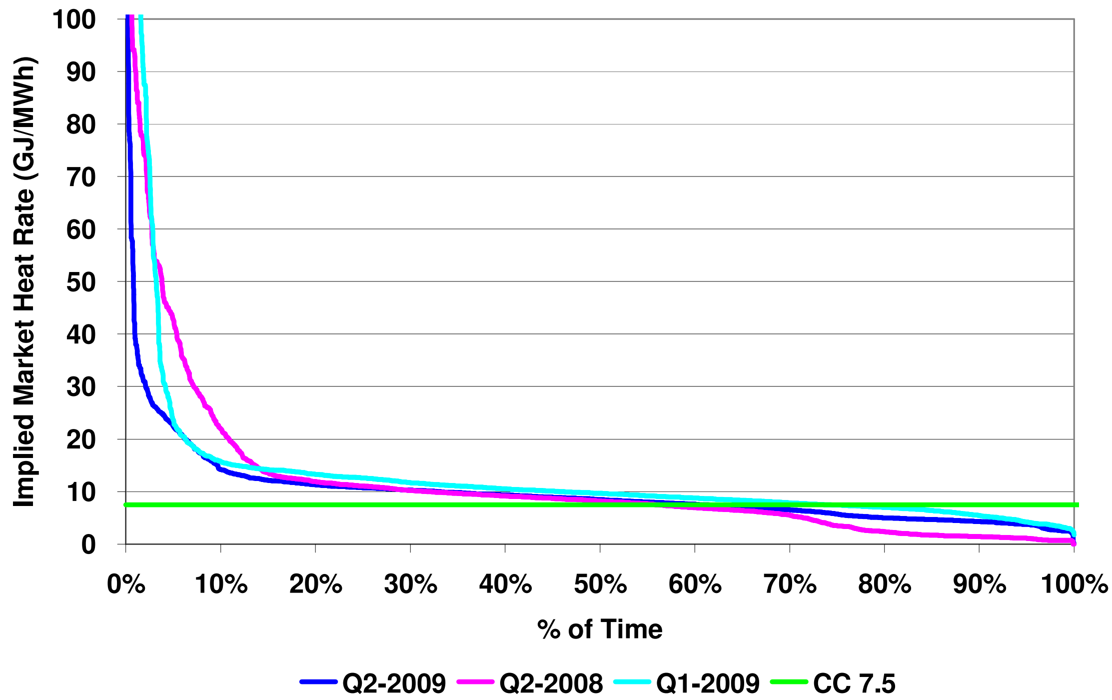


Figure 7 - Implied Market Heat Rates On-Peak

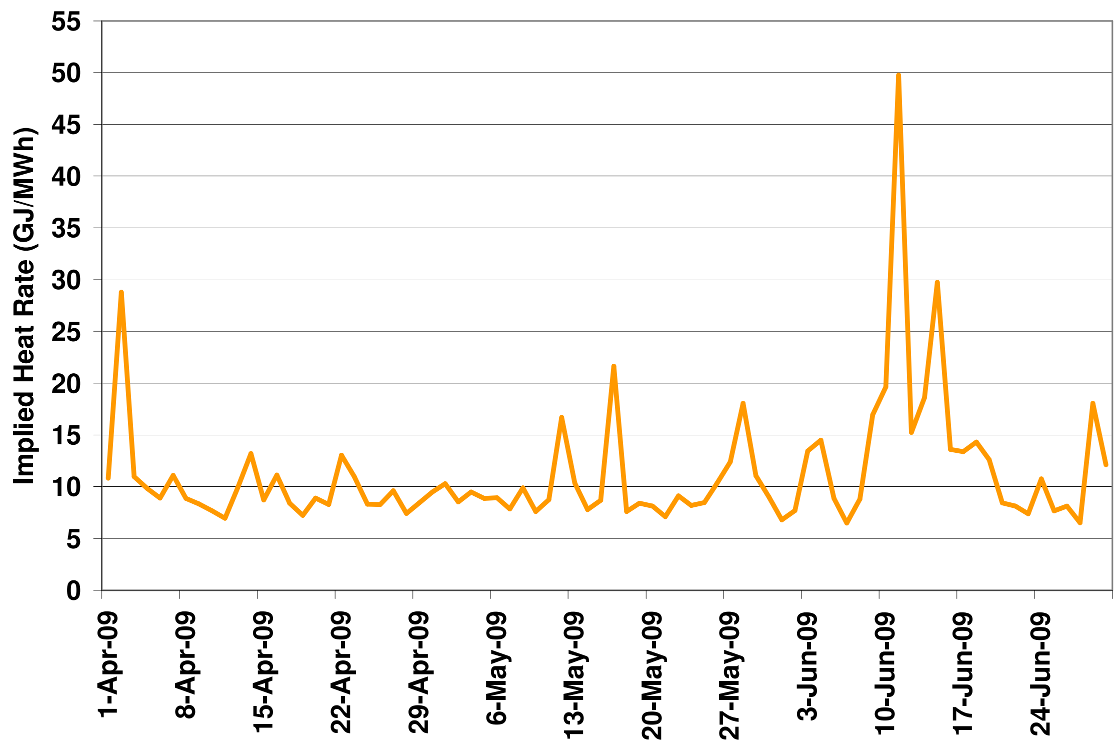
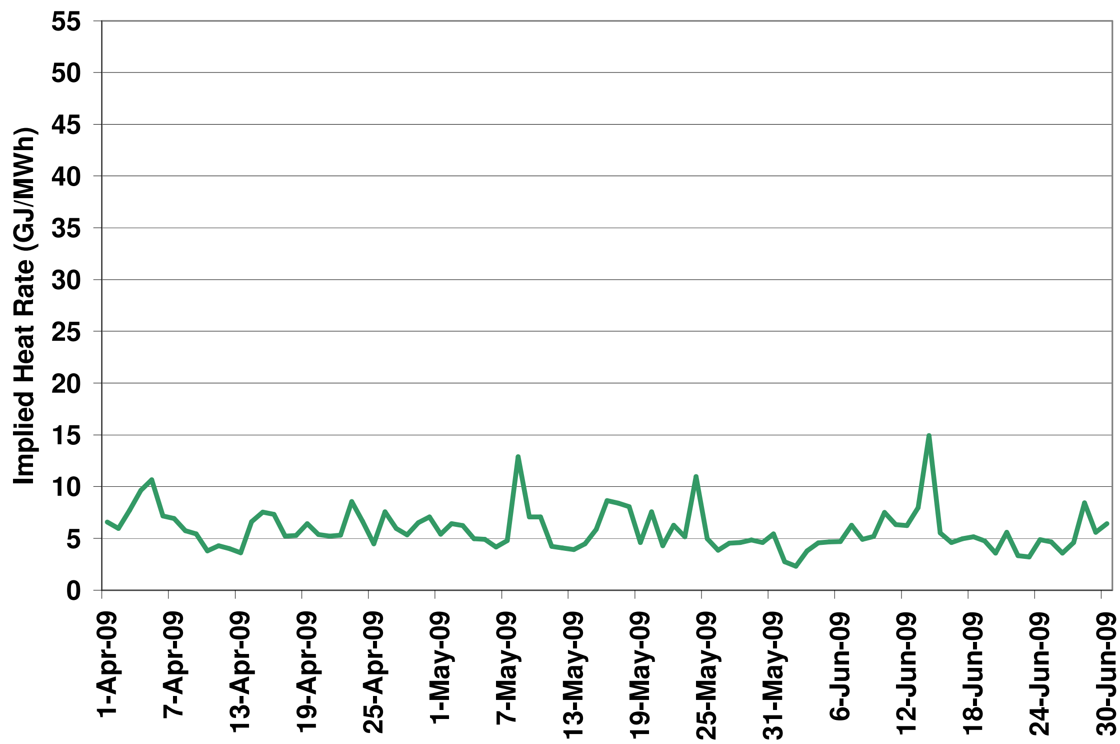


Figure 8 – Implied Market Heat Rates Off-Peak

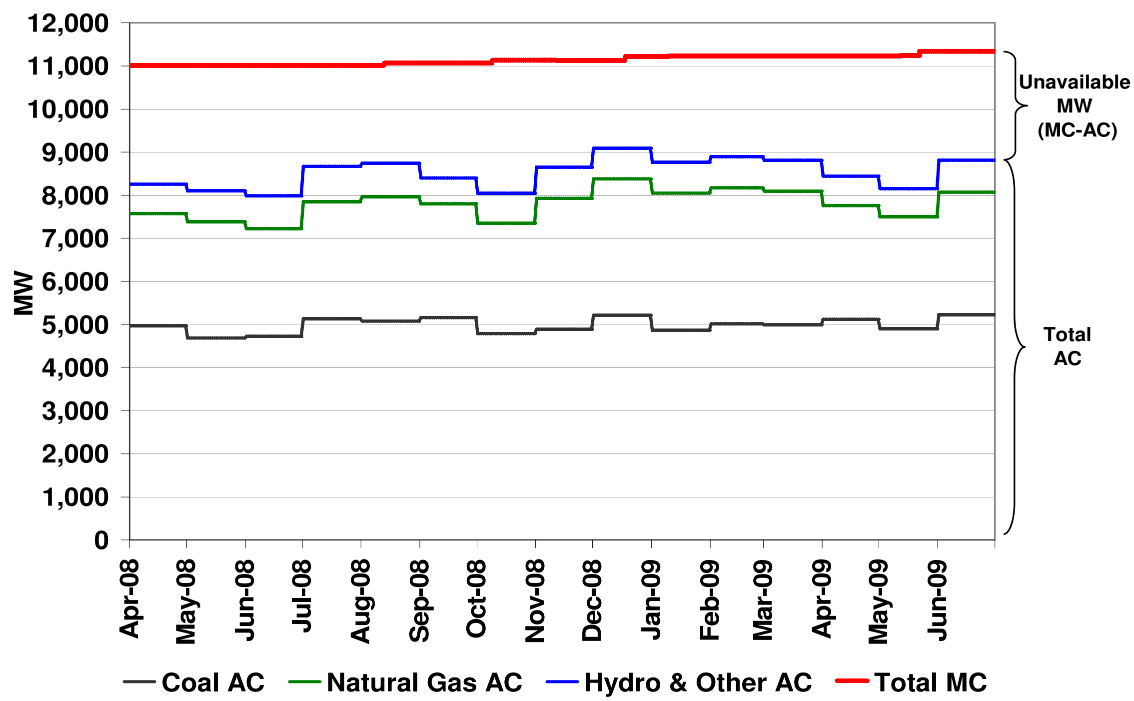


APPENDIX B – SUPPLY AVAILABILITY METRICS

Table 2 - Availability Factor and Capacity Factor

Fuel Type	Quarter	Average MC	Average AC	Availability Factor	Generation	Capacity Factor
		[A] (MW)	[B] (MW)	[C]=[A]/[B]	[D] (GWh)	[E]= [Dx1000]/([A]xhrs)
All Fuels	Q2/09	11,282	8,468	75%	14,727	60%
	Q1/09	11,228	8,819	79%	15,755	65%
	Q2/08	11,009	8,116	74%	14,440	60%
Coal	Q2/09	6,011	5,081	85%	9,955	76%
	Q1/09	6,011	4,953	82%	10,186	78%
	Q2/08	6,011	4,792	80%	9,740	74%
Natural Gas	Q2/09	4,356	2,695	62%	4,314	45%
	Q1/09	4,302	3,147	73%	5,144	55%
	Q2/08	4,083	2,603	64%	4,068	46%
Hydro & Other	Q2/09	915	692	76%	458	23%
	Q1/09	915	720	79%	424	21%
	Q2/08	915	721	79%	632	32%
Wind	Q2/09	497	n/a	n/a	307	28%
	Q1/09	497	n/a	n/a	447	42%
	Q2/08	497	n/a	n/a	341	31%

Figure 9 – Availability Capacity (AC) vs Maximum Capacity (MC)



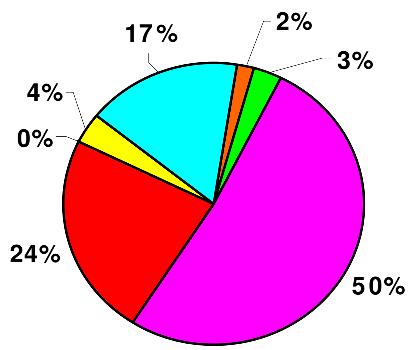
APPENDIX C – INTERTIE METRICS

Table 3 - Intertie Statistics

	British Columbia			Saskatchewan			Overall		
	Imports (MWh)	Exports (MWh)	Net Imports (MWh)	Imports (MWh)	Exports (MWh)	Net Imports (MWh)	Imports (MWh)	Exports (MWh)	Net Imports (MWh)
Apr	90,404	32,962	57,442	41,346	4,025	37,321	131,750	36,987	94,763
May	149,735	20,619	129,116	64,624	6,940	57,684	214,359	27,559	186,800
Jun	152,934	6,722	146,212	38,885	3,852	35,033	191,819	10,574	181,245
Q2-2009	302,669	27,341	275,328	103,509	10,792	92,717	406,178	38,133	368,045

Figure 10 - Market Share of Importers and Exporters

IMPORTS



EXPORTS

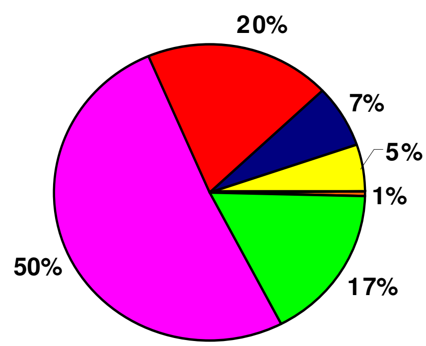


Figure 11 - Intertie Utilization Q2/09

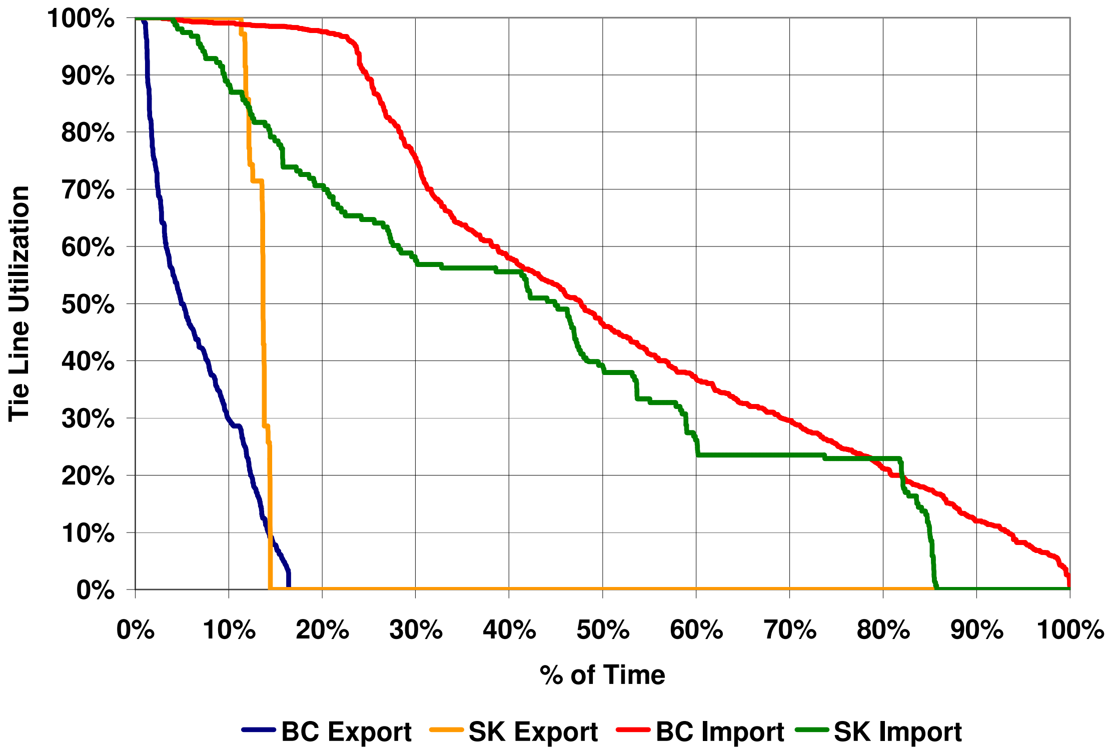


Figure 12 - Imports with Trade-Weighted Prices

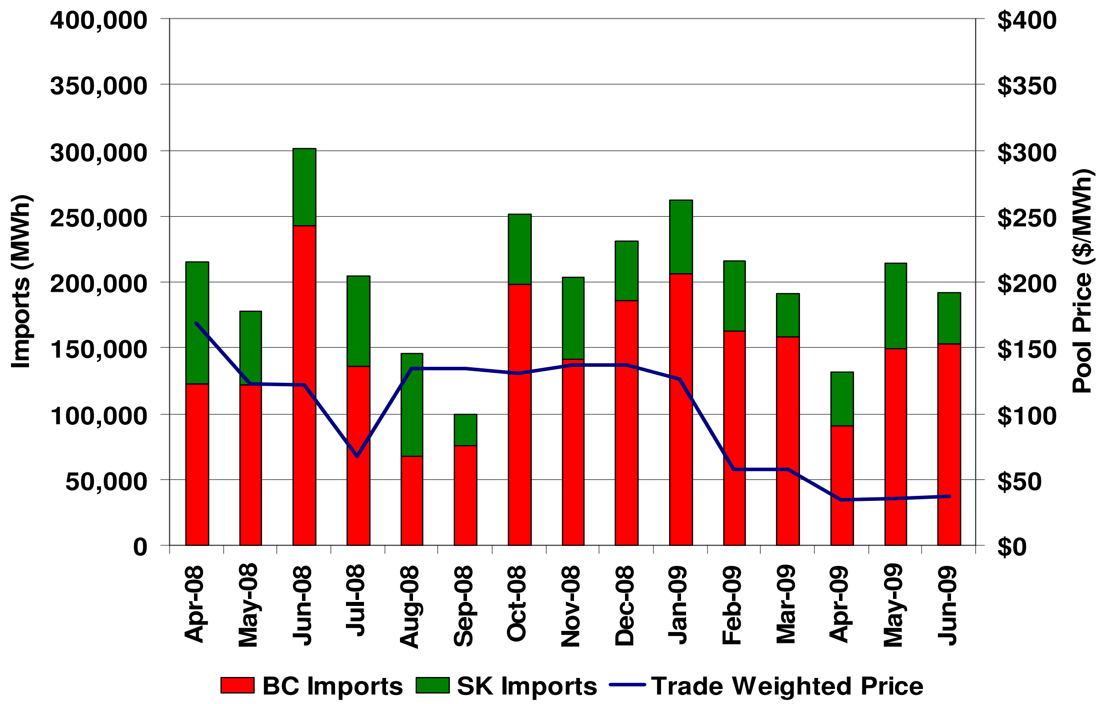


Figure 13 - Export with Trade-Weighted Prices

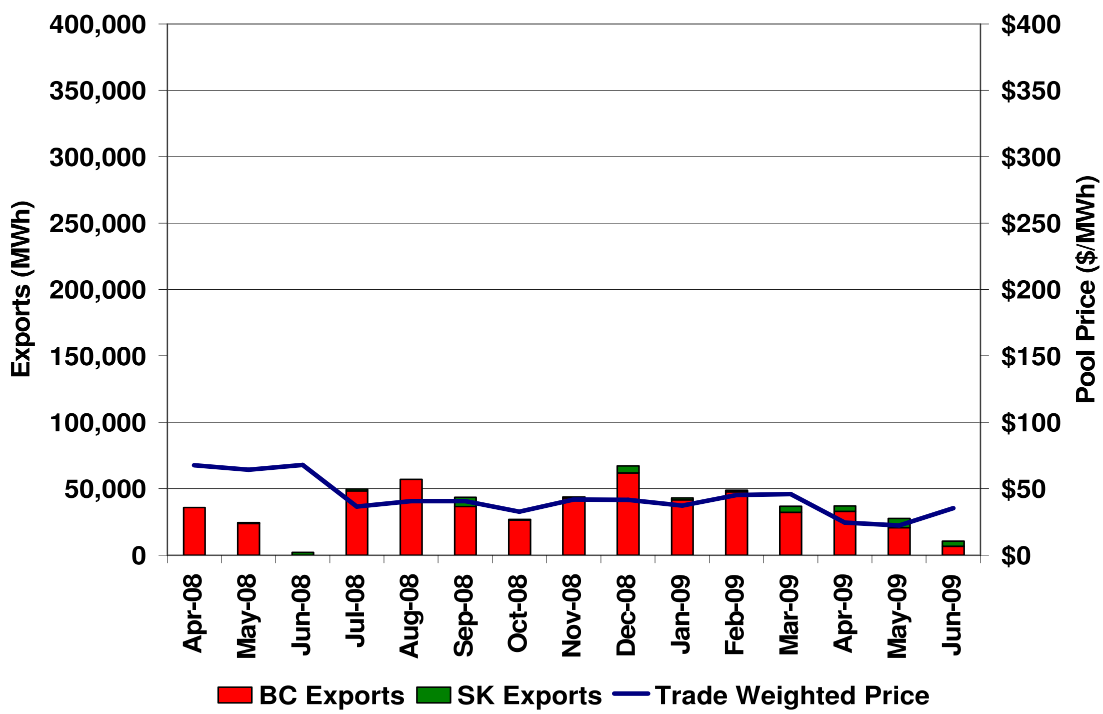


Figure 14 - On-Peak Prices in Other Markets

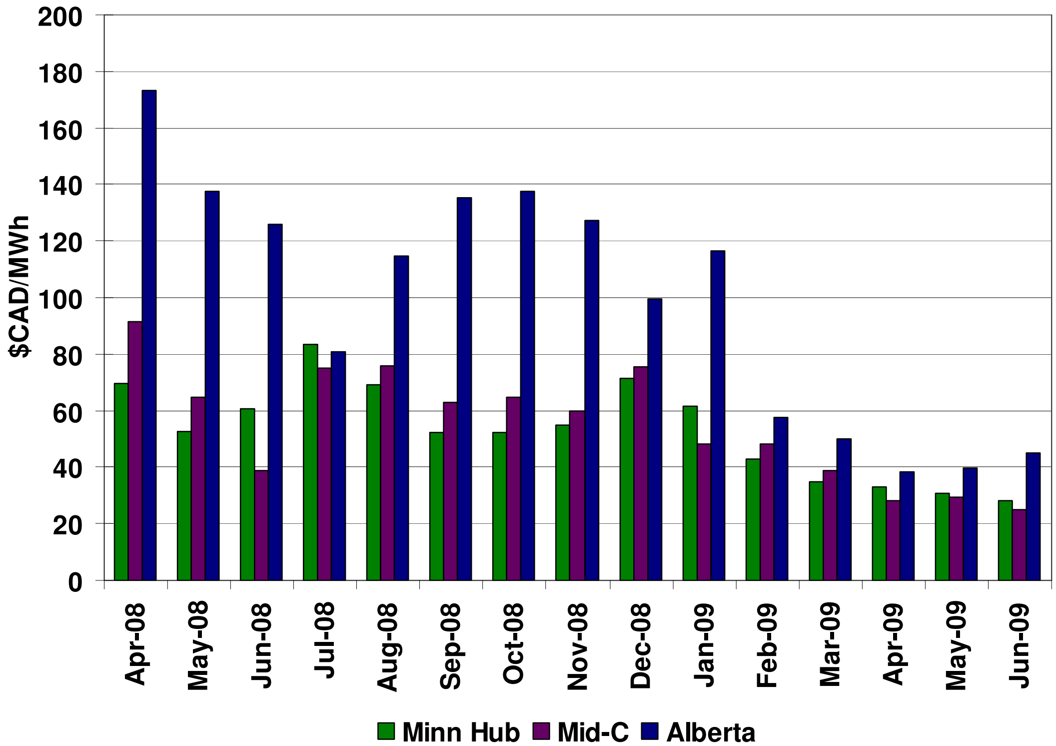
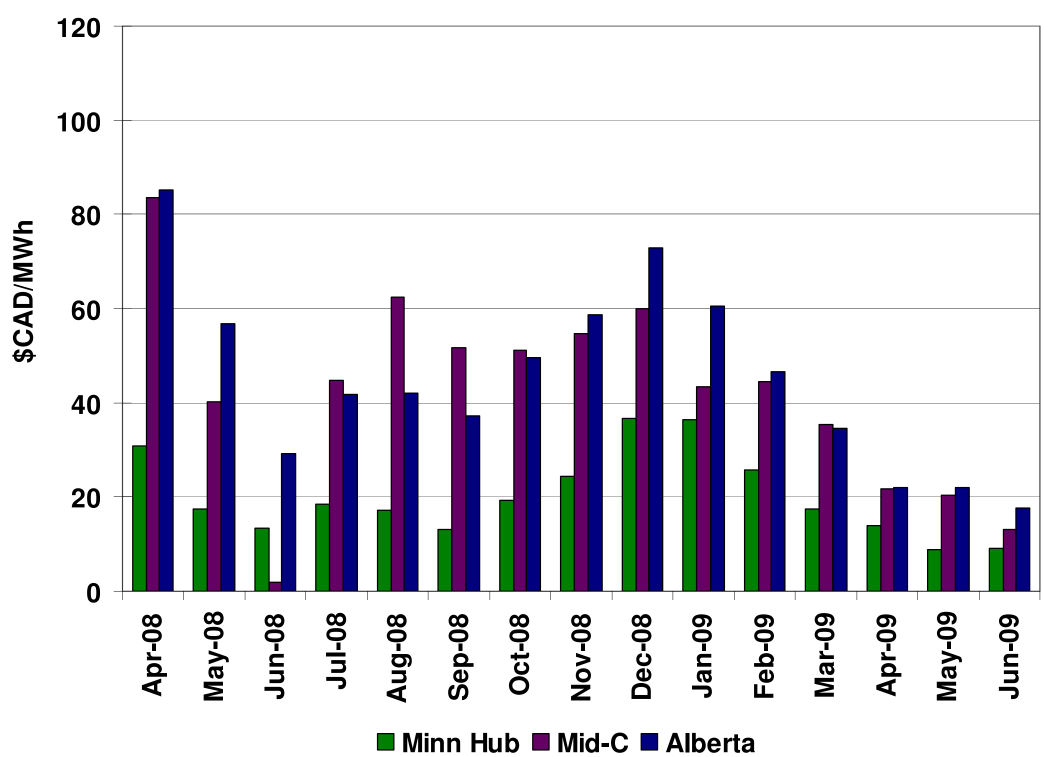


Figure 15 - Off-Peak Prices in Other Markets



APPENDIX D – OPERATING RESERVE MARKET METRICS

Ancillary services are the system support services that ensure system stability and reliability. The Alberta Interconnected Electric System (AIES) is required to carry sufficient operating reserves in order to assist in the recovery of any unexpected loss of generation or an interconnection. Operating reserves are competitively procured by the AESO through the Alberta NGX Exchange (NGX) and over the counter (OTC). Standard operating services products (contracts) include active and standby products for each of Regulating, Spinning, and Supplemental operating reserves. The majority of active operating reserve products are indexed and settled against the Pool price prevailing during the contract period. Standby operating reserve products are priced in a similar manner to options with a fixed premium and an exercise price (activation price). The activation price is only paid in the event that the contract is activated.

Figure 16 - Active Settlement Prices - All Markets (NGX and OTC)

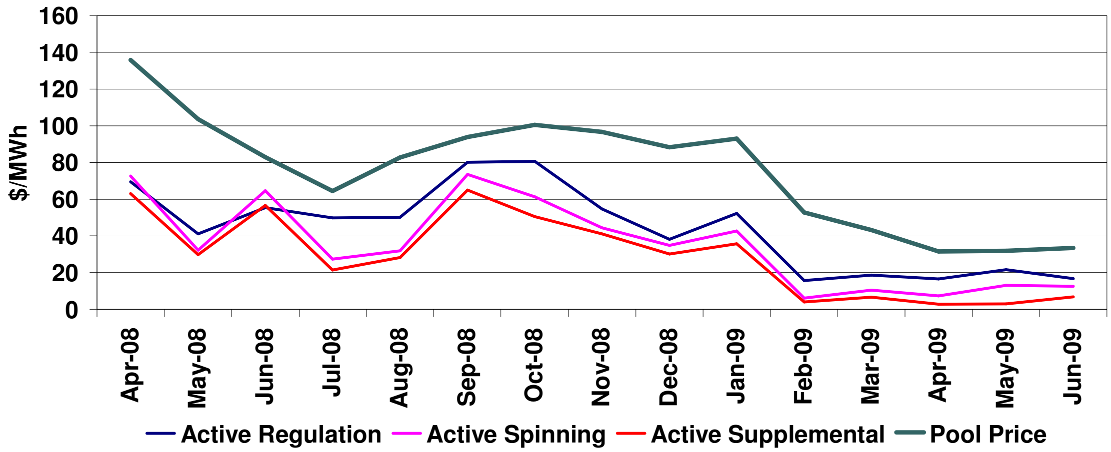


Figure 17 – Standby Premiums – All Markets (NGX and OTC)

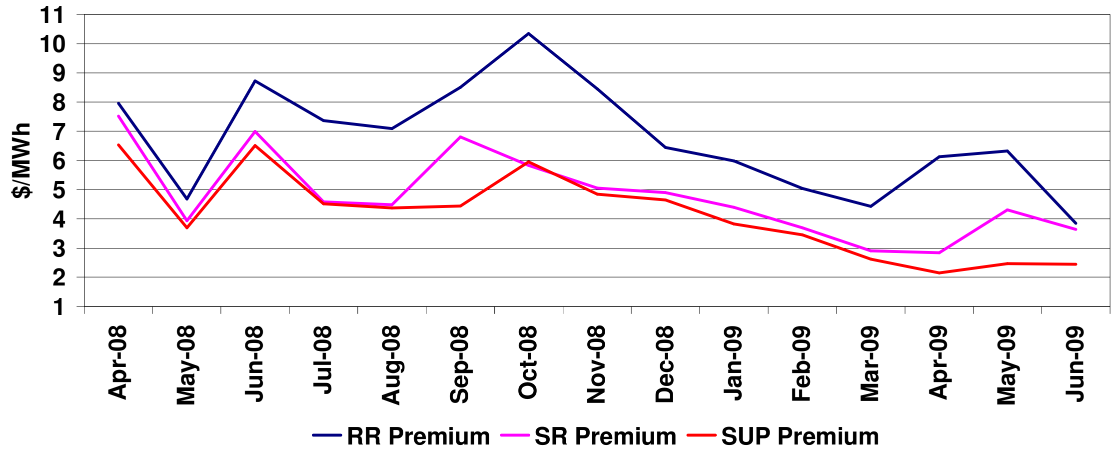


Figure 18 - Standby Activation Prices – All Markets (NGX and OTC)

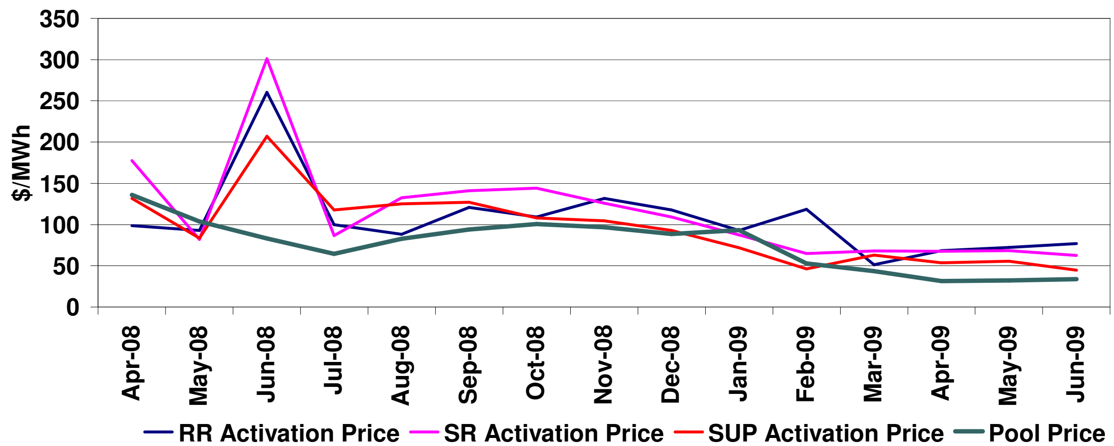


Figure 19 – Standby Activation Rates

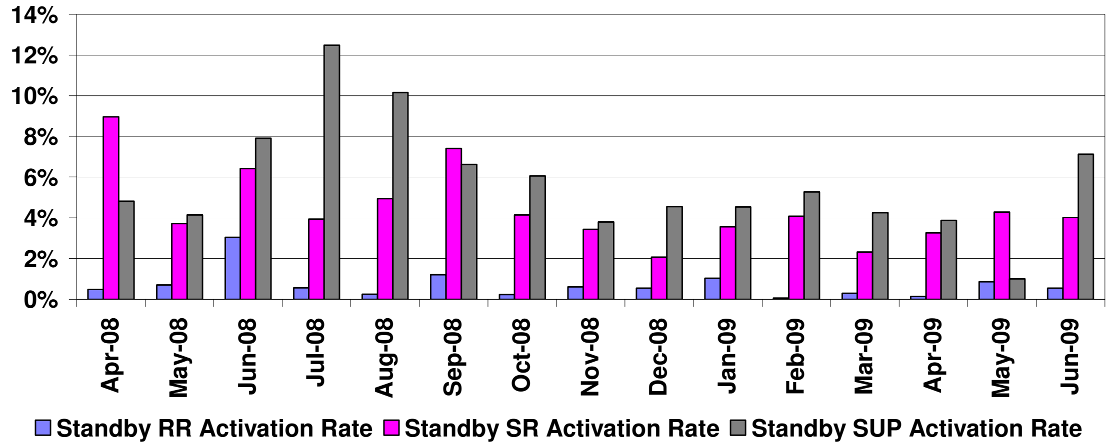


Figure 20 – OTC Procurement as a % of Total Procurement

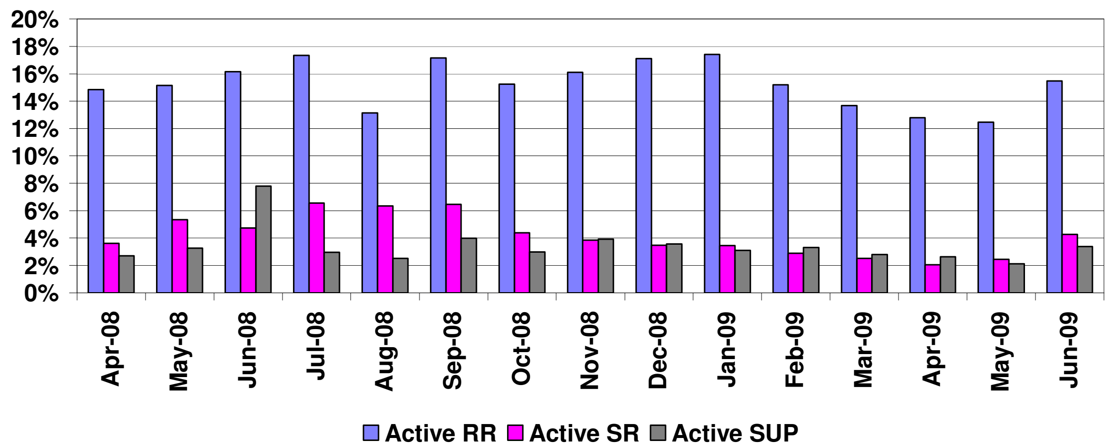


Figure 21 - Active Regulating Reserve Settlement by Market

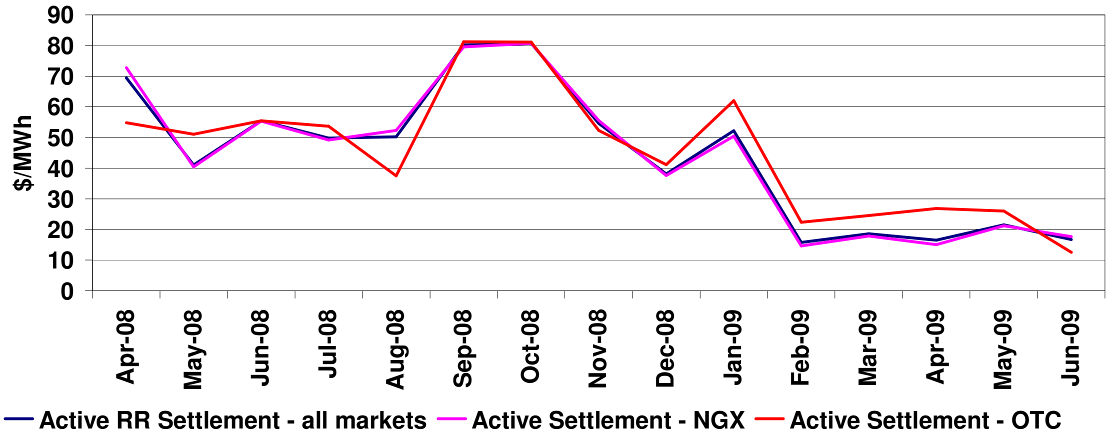


Figure 22 – Active Spinning Reserve Settlement Price by Market

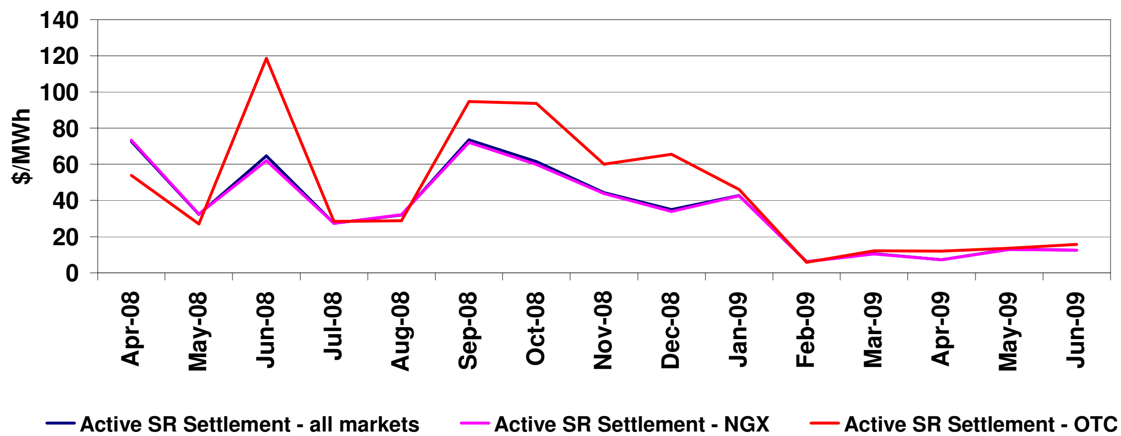


Figure 23 – Active Supplemental Reserve Settlement Price by Market

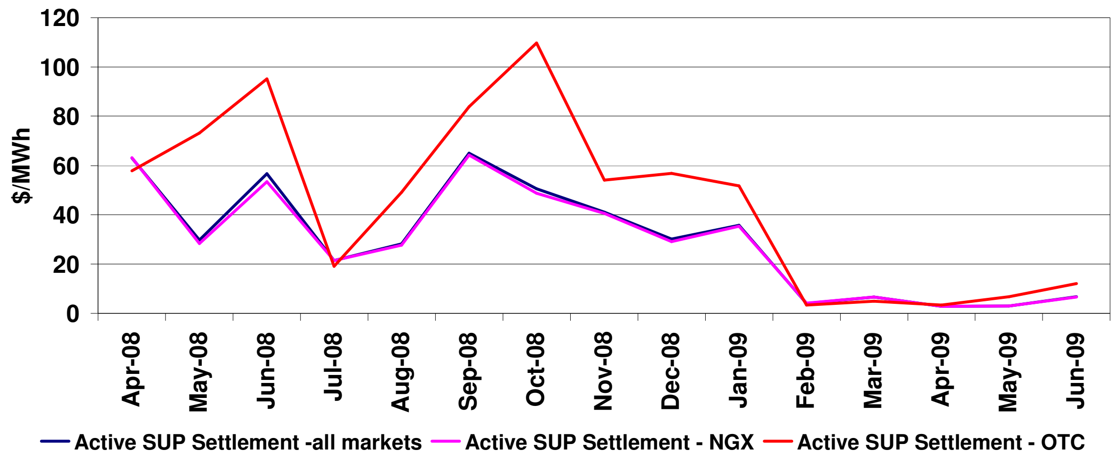


Figure 24 – Active Regulating Reserve Market Share by Fuel Type

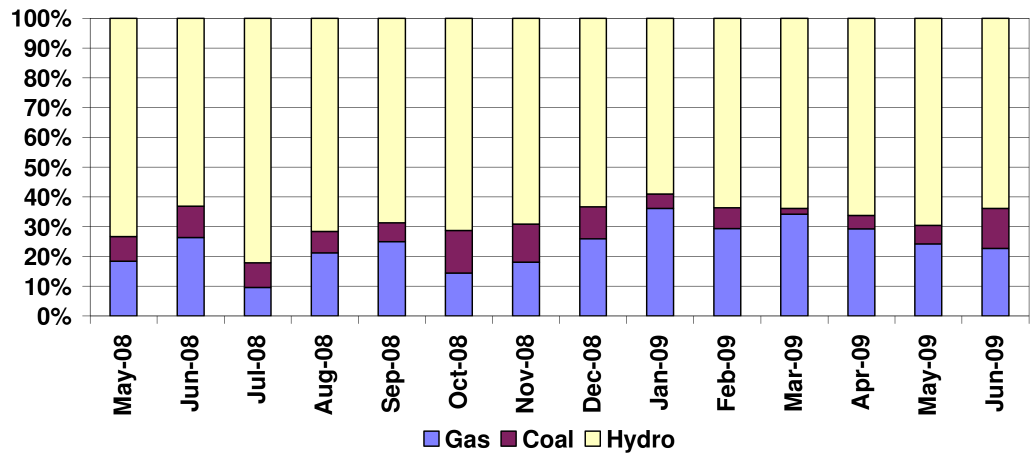


Figure 25 Active Spinning Reserve Market Share by Fuel Type

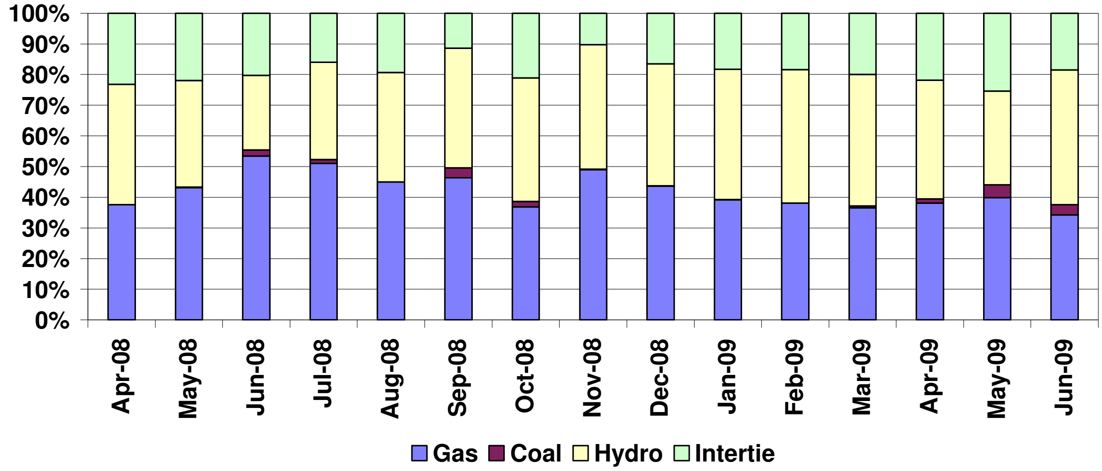
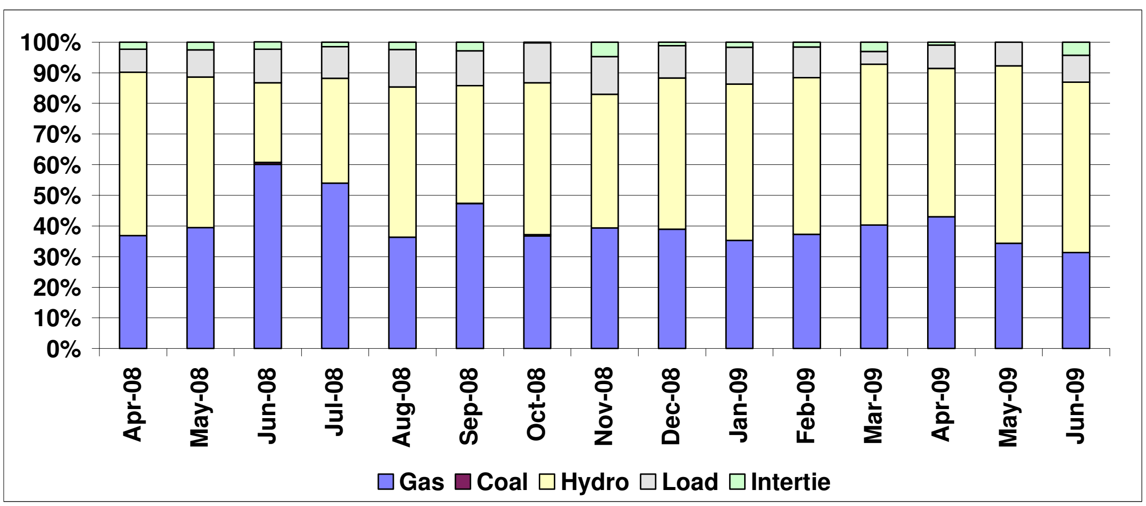


Figure 26 – Active Supplemental Reserve by Fuel Type



APPENDIX E – DDS METRICS

Table 4 - DDS Costs and Revenues

Month	Total Payment ($M)	Total Dispatched (MWh)	Total Energy Production (MWh)	Estimated DDS Charge ($/MWh)	Estimated Revenue to DDS
	[A]	[B]	[C]	[A]/[C]	[A]/[B]
April	$0.88	64,441	4,491,229	$0.20	$13.64
May	$0.43	34,077	4,558,186	$0.09	$12.48
June	$1.06	99,727	4,340,300	$0.24	$10.65
Total	$2.37	198,245	13,389,714	$0.18	$11.94

Figure 27 - Average Daily TMR, Available, Eligible & Dispatched DDS Volumes (MW)

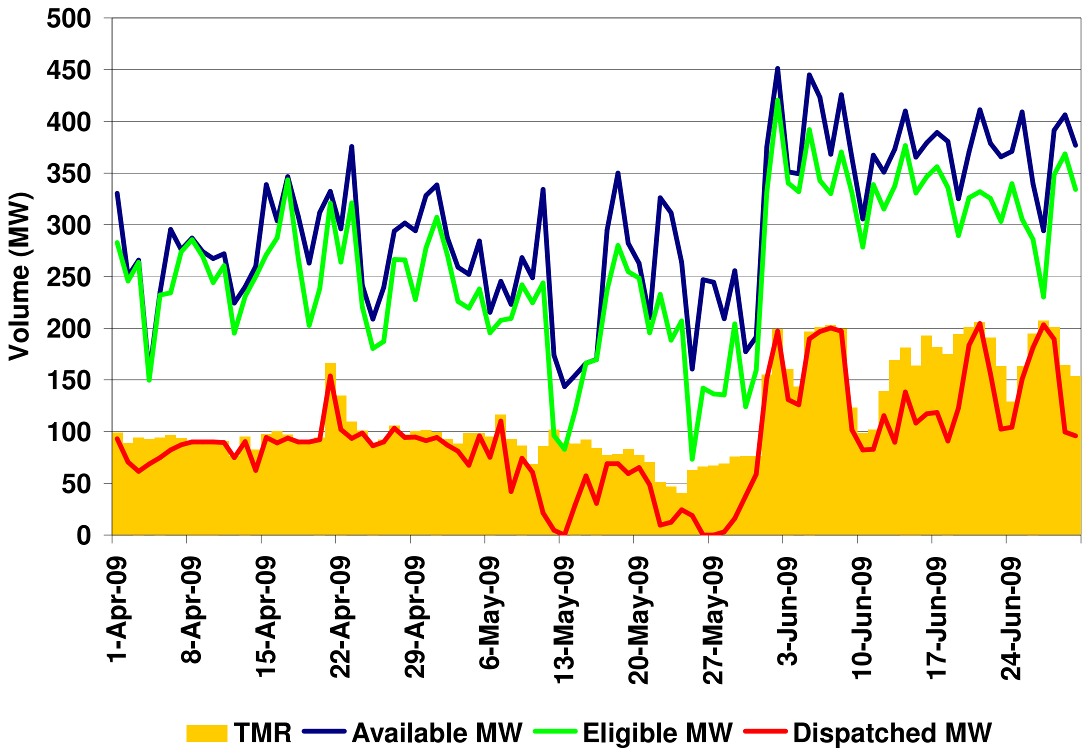


Figure 28 - Average Daily DDS Dispatched and Constrained Down Volume (MW)

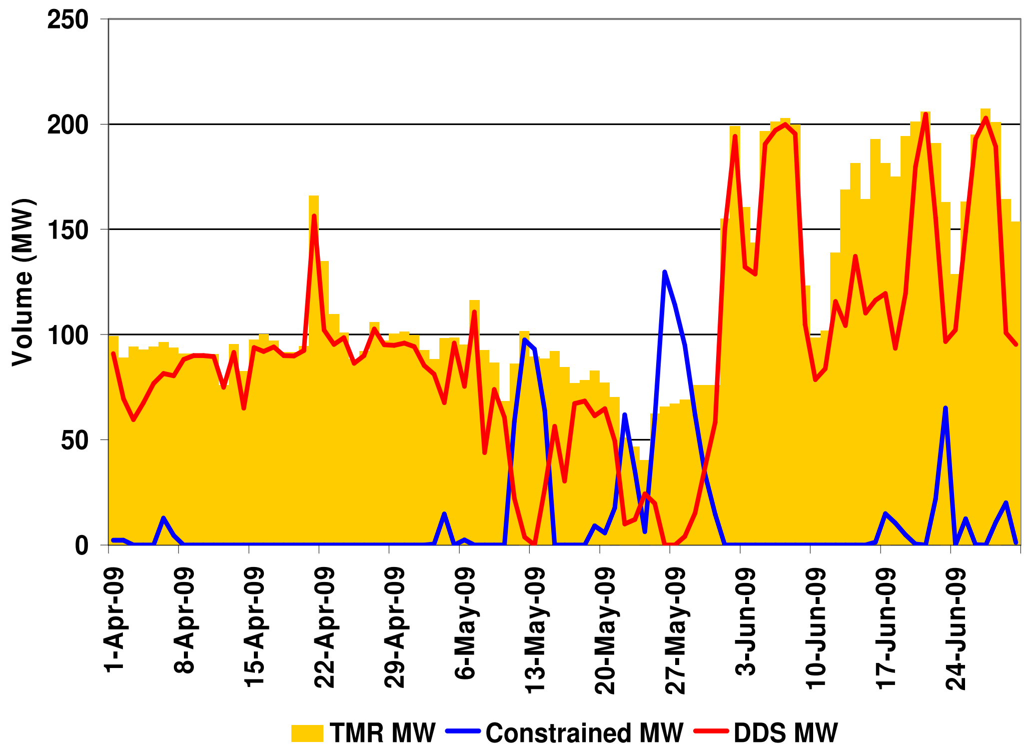


Figure 29 - Average Weekly DDS Market Share by Submitting Participants

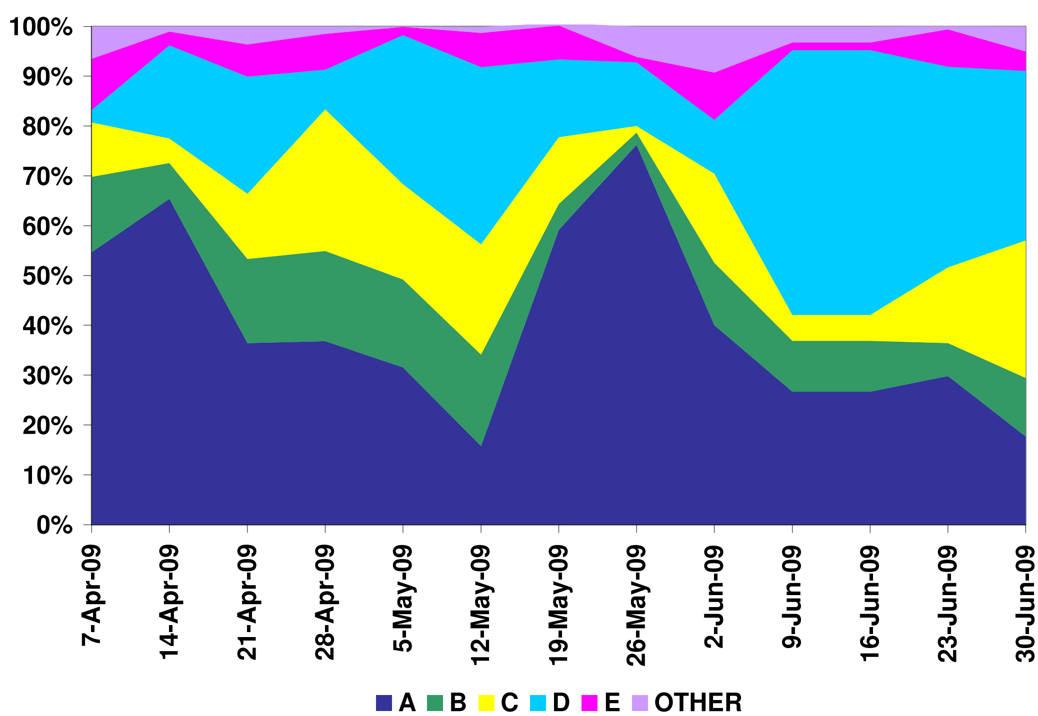
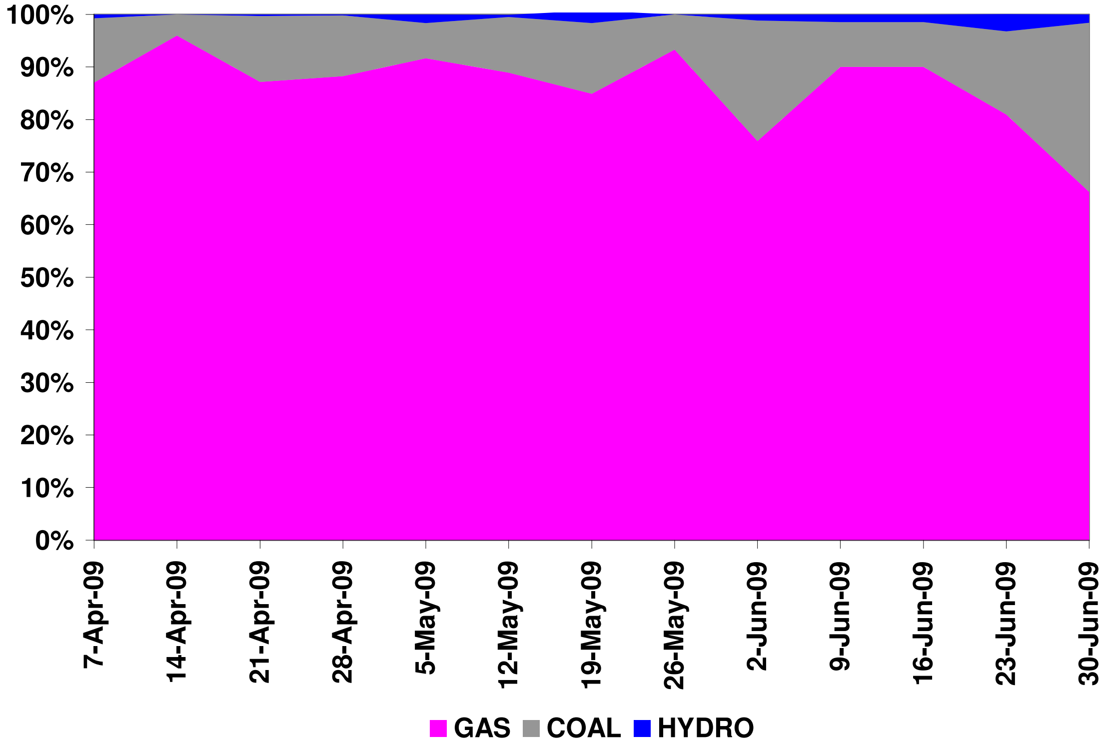


Figure 30 - Average Weekly Market Share by Fuel Type



APPENDIX F – FORWARD MARKET METRICS

Figure 31 - Volume by Trading Month

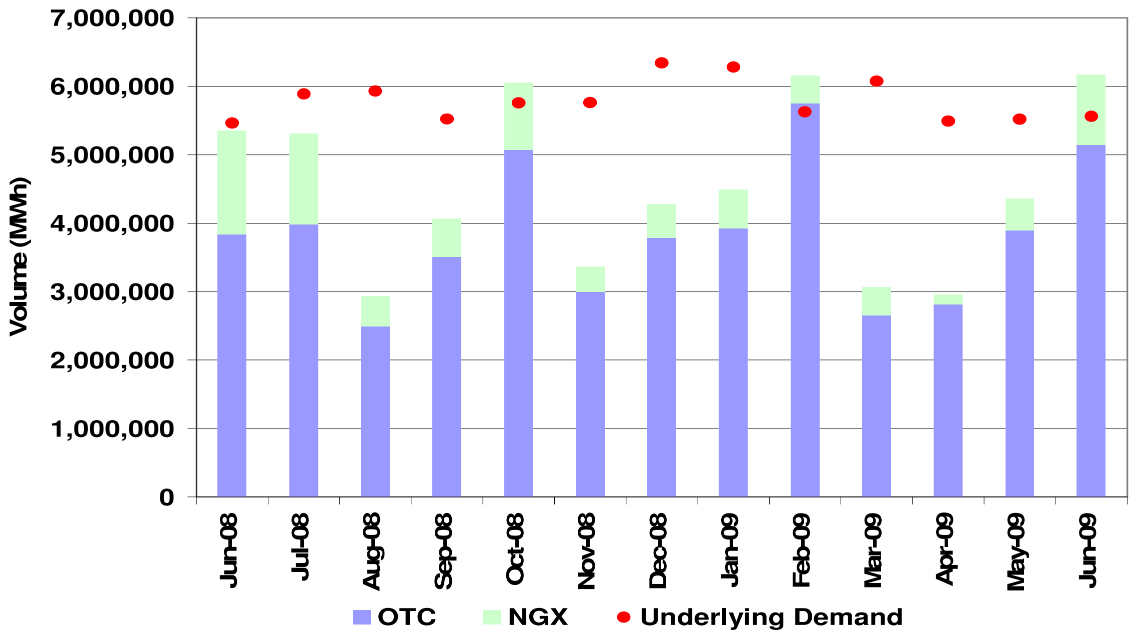


Figure 32 - Number of Participants by Trading Month