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MSA Report

Quarterly Report

January – March, 2009

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Market Surveillance Administrator

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

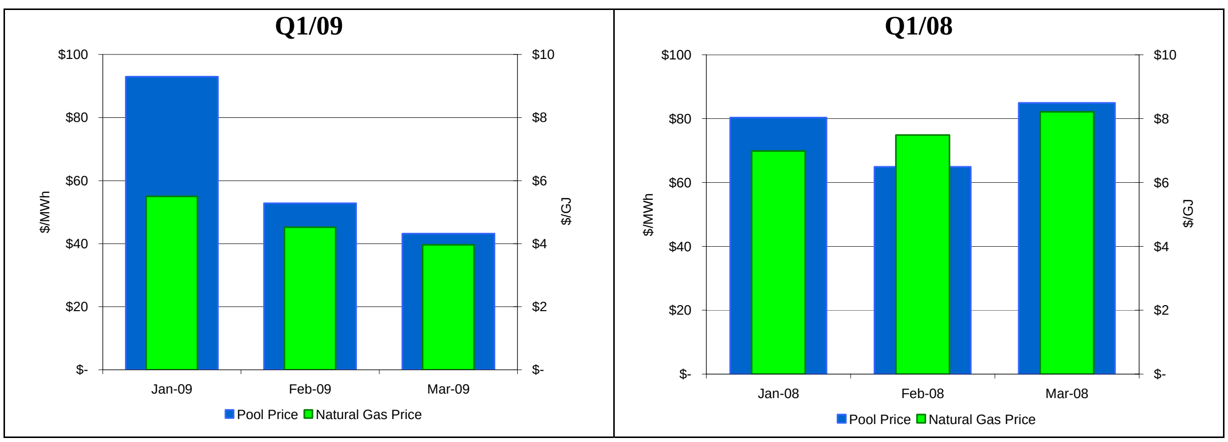
1 WHOLESALE MARKET FUNDAMENTALS

The average Pool price for Q1/09 was $63.36/MWh which is 33% lower than Q4/08 and 17.6% lower than Q1/08. However, Q1/07 average Pool price was only seven cents lower ($63.29/MWh). Strong wind, a declining natural gas price, and the associated waning reference price were contributing factors to the observed soft Pool prices. January's high average price of $92.97/MWh was primarily due to the events during the week of January 20-26, 2009. Section 3 examines the price drivers of these events.

Natural gas prices (AECO-C) have continued to decline since the highs of last summer (Figure 3 in Appendix A). Overall, the Q1/09 natural gas price averaged $4.67/GJ which was 38% lower than Q1/08 and 26% lower than Q4/08. Average price in March of 2009 was 52% lower than March 2008. Figure i illustrates Q1/09 and Q1/08 monthly average Pool and natural gas prices. In terms of implied market heat rate (Pool price/natural gas price), the average for Q1/09 was 13.35 GJ/MWh compared with 10.34 GJ/MWh in Q1/08. Although Pool prices in Q1/09 are down from Q1/08, the market heat rate rose. Natural gas prices fell even faster than power prices.

The overall pricing over Q1/09 in dollar terms suggests the market was not generally tight which appears at odds with the high market heat rate. This may be further evidence that the relationship between Pool prices and natural gas prices in Alberta is not as strong as it once was.

Figure i - Summary of Monthly Average Pool Price and Natural Gas Price



Declining natural gas price has resulted in a decreasing Reference Price (below which dispatch down service is used to reconstitute Pool price). The Reference Price as per ISO rule 3.10 (b) is based on 12.5 GJ/MWh multiplied by the natural gas price. Figure ii shows the Reference Price over the last 16 months and the gradual reduction from $140/MWh last July to $45/MWh in April. Figure iii illustrates the persistent shelf occurring in the monthly SMP duration curves at the applicable monthly Reference Price. January and March SMP was "stuck" near or at the Reference Price 10% of the time, while February was “stuck” at the Reference Price 15% of the time.

These shelves in the price duration curves are an artifact of the price reconstitution process and negatively impact price fidelity in the market.

Figure ii - Reference Price

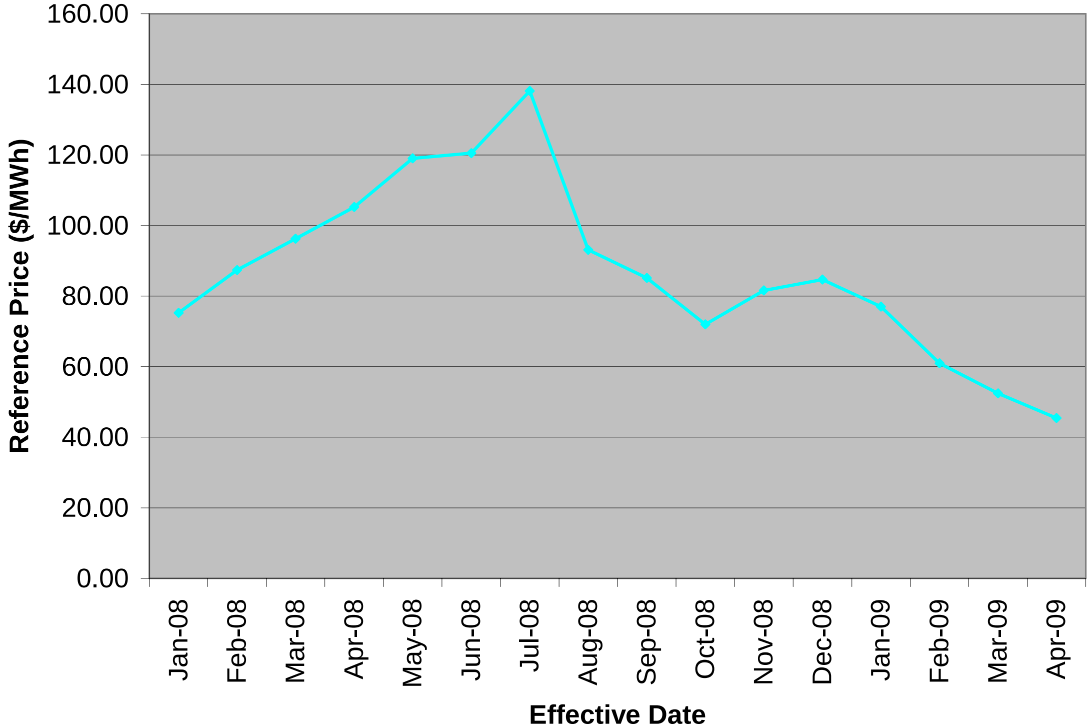
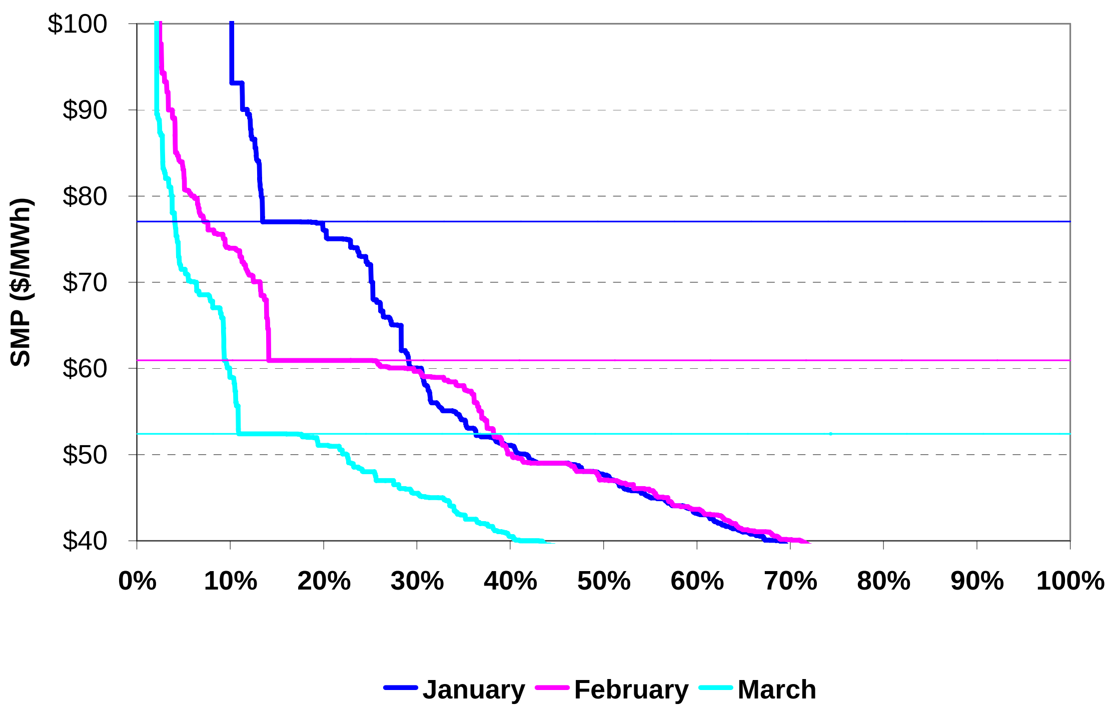


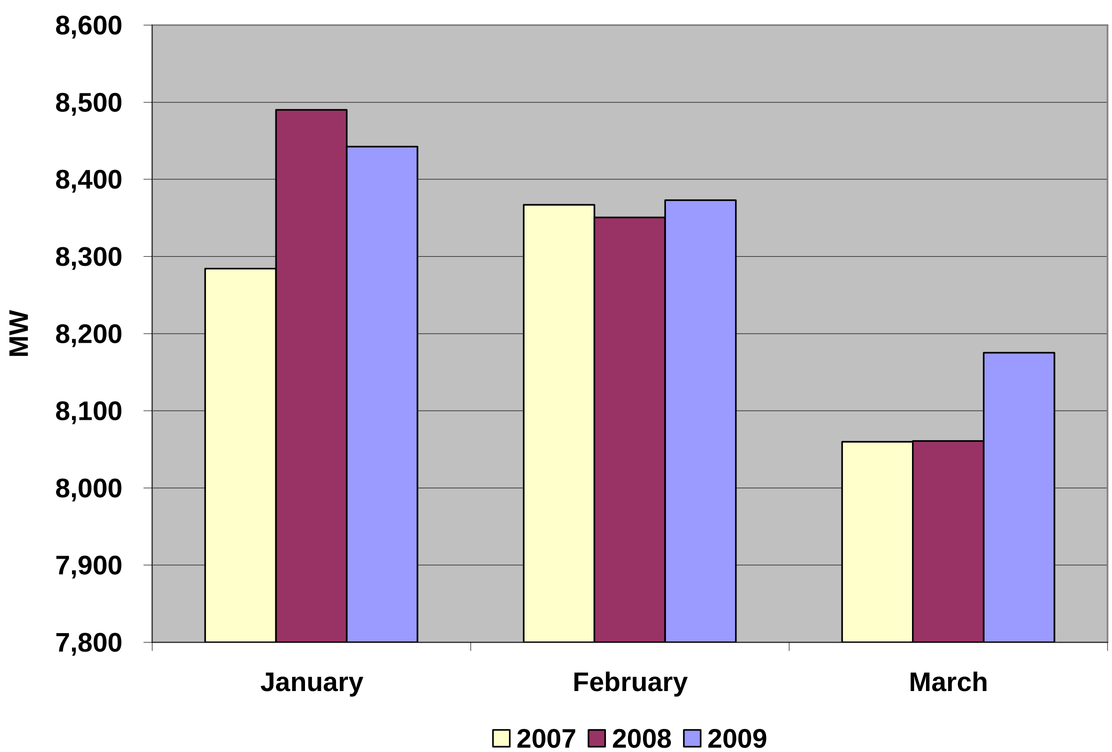
Figure iii - SMP Duration Curves, Q1/09



Quarterly net imports on the BC intertie were at 407,000 MWh, some 324,000 MWh less than in Q1/08. However, this is just slightly more than net imports in Q4/08 (394,000 MWh). Net imports for Q1/09 on the SK intertie were down slightly compared to Q4/08 (134,000 MWh, 154,000 MWh respectively). For further details see Table 2 in Appendix B. Although, the Pool prices for much of Q1/09 were relatively soft, they were higher than the Mid-C and Minnesota Hub markets (See Figure 13 and 14 in the appendices).

In the MSA's 2008 Year in Review report, we commented on how load growth appeared to have stalled. In Q1/09, average load increased slightly compared to the two previous years. Q1/09 load averaged 8,329 MW compare to 8,299 MW in Q1/08 and 8,233 MW in Q1/07. Q1/09 load grew 0.3% compared to Q1/08. Average load for March was approximately 100 MW higher than the previous two years (Figure iv). This increase in load can be at least in part attributed to a colder than average month. The average temperature for March 2009 was -4.4 degrees Celsius with extremes from plus 12.8 degrees to minus 26.2 degrees as per data at the Calgary International Airport. March 2008 averaged zero degrees Celsius with extremes from 14.9 degrees to minus 14.6. The average temperatures for March 2007 were even milder with and average temperature of 1.6 degrees Celsius.[1]

Figure iv - Average Load



[1] Environment Canada, http://www.climate.weatheroffice.ec.gc.ca.html

2 SUPPLY AVAILABILITY ANALYSIS

2.1 Background

In the past, the MSA has reported on PPA outages in its quarterly reports, however it has recently undertaken an analysis of the availability of generation assets supplying into the merit order. With the introduction of the 'Quick Hits' rules package on December 3, 2007, all units offering into the merit order report a Maximum Capability (MC) and an Available Capability (AC), with the difference representing MWs unavailable to the merit order. Future Quarterly Reports will present a streamlined version of this analysis in the wholesale Energy Market Metrics Appendix.

Each generating asset, must submit an MC, as the maximum quantity (MW) that the asset is capable or providing under optimal conditions, while complying will all applicable ISO Rules and Tariff conditions. This defined level of MC may be greater or smaller than a unit's Maximum Continous Rating (MCR), depending on factors such as the actual operational limits of the unit or behind the fence obligations. Some units, such as wind, Small Power Producers, and imports who do not offer into the merit order, do not submit MC and AC values, and are therefore excluded from this analysis.

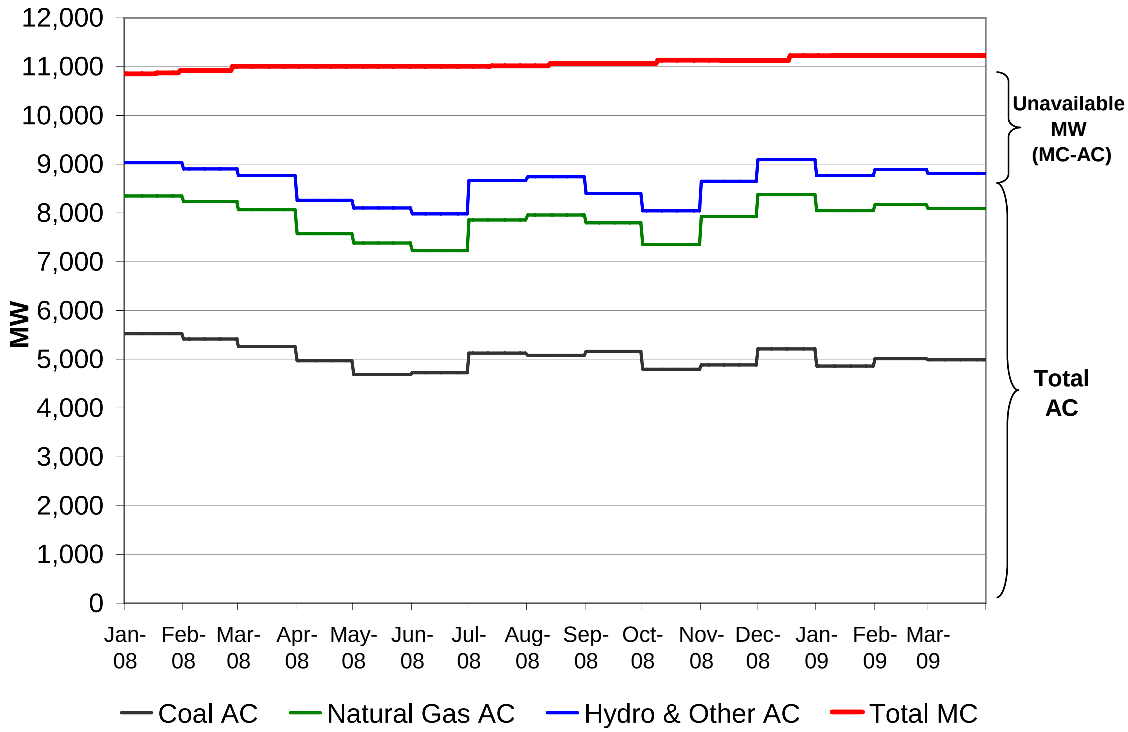
2.2 Overall Availability

The AC of each generating asset is the quantity (MW) that is physically capable of being provided during each hour of the trading day. For each hour each generating unit must have submitted an AC value. If the AC of a unit is less than the MC, the generating unit must also submit an acceptable operational reason for the AC variance.

Figure v presents a system summary for the past fifteen months plotting the total MC, and the monthly average AC by fuel type. Note that the plots of AC by fuel type are cumulative, such that the plot of 'Hydro and Other AC' also respresents the total monthly average AC.

MC values are relatively stable through time, changing only as new generating assets are added or retired. The gradual increase in system MC shown in Figure v is largely due to the addition of gas fired generation discussed below.

Figure v - System Summary - Total MC, Monthly Average AC by Fuel



The monthly average AC values are more variable than MC, and cumulatively show a pattern of seasonality that tracks the seasonality of load. This pattern driven by facility owners tending to plan their maintenance outages to coincide with troughs in seasonal demand (spring and fall), and to a lesser extent seasonal derates due to ambient air temperature.

The plots of monthly average AC smooths the hour to hour volatility of the total AC considerably. Notwithstanding this smoothing effect, Figure v shows a persistent gap between the MC and AC of approximatlely 2000 MW. Given the definition of MC, as the maximum capability under *optimal conditions* it is not unusual that AC values are somewhat less than MC values. This persistently unavailable capacity can be attributed to the cumulative effects of a variety of factors including:

- Planned outages;
- Derates due to ambient air temperature;
- Unplanned outages; and,
- Long lead time units that appear as an outage or heavily derated when offline, but are potentially available with advanced notice.

Some cogen units have persistent differences between AC and MC as output may be constrained by industrial processes.

Table i presents a summary of the quarterly average MC and AC values by fuel type, and the total quarterly generation by fuel type. An availability factor, calculated as the quarterly average AC over the quarterly average MC is presented, along with a capacity factor, calculated as total quarterly generation over MC. Data is presented for Q1-09, Q4-08, and Q1-08, allowing for quarter-over-quarter, and year-over-year comparisons.

Table i - Quarterly Average MC, Quarterly Average AC and Generation by Fuel Type

Fuel Type	Quarter	Average MC [A]	Average AC [B]	Availability Factor [C]=[A]/[B]	Generation [D]	Capacity Factor [E]= [Dx1000]/([A]xhrs)
		(MW)	(MW)		(GWh)	
All Fuels	Q1/09	11,228	8,819	79%	15,755	65%
	Q4/08	11,138	8,594	77%	15,676	64%
	Q1/08	10,934	8,902	81%	16,164	68%
Coal	Q1/09	6,011	4,953	82%	10,186	78%
	Q4/08	6,011	4,964	83%	10,544	79%
	Q1/08	6,009	5,399	90%	11,321	86%
Natural Gas	Q1/09	4,302	3,147	73%	5,144	55%
	Q4/08	4,212	2,921	69%	4,715	51%
	Q1/08	4,011	2,818	70%	4,429	51%
Hydro & Other	Q1/09	915	720	79%	424	21%
	Q4/08	915	709	77%	417	21%
	Q1/08	914	685	75%	414	21%

System wide, the availability factor in Q1-09 was 79%, with the availability of coal units tending slightly above the average and gas units somewhat below. The capacity factor of each fuel type, relative to the availability factor, is instructive to the type of generation each fuel supplies to the grid, be it base load for the coal plants, or peaking generation of the hydro plants. Data on gas plants have been aggregated, so the distinction between gas peaking, and baseload gas cogen is blended in the capacity factor.

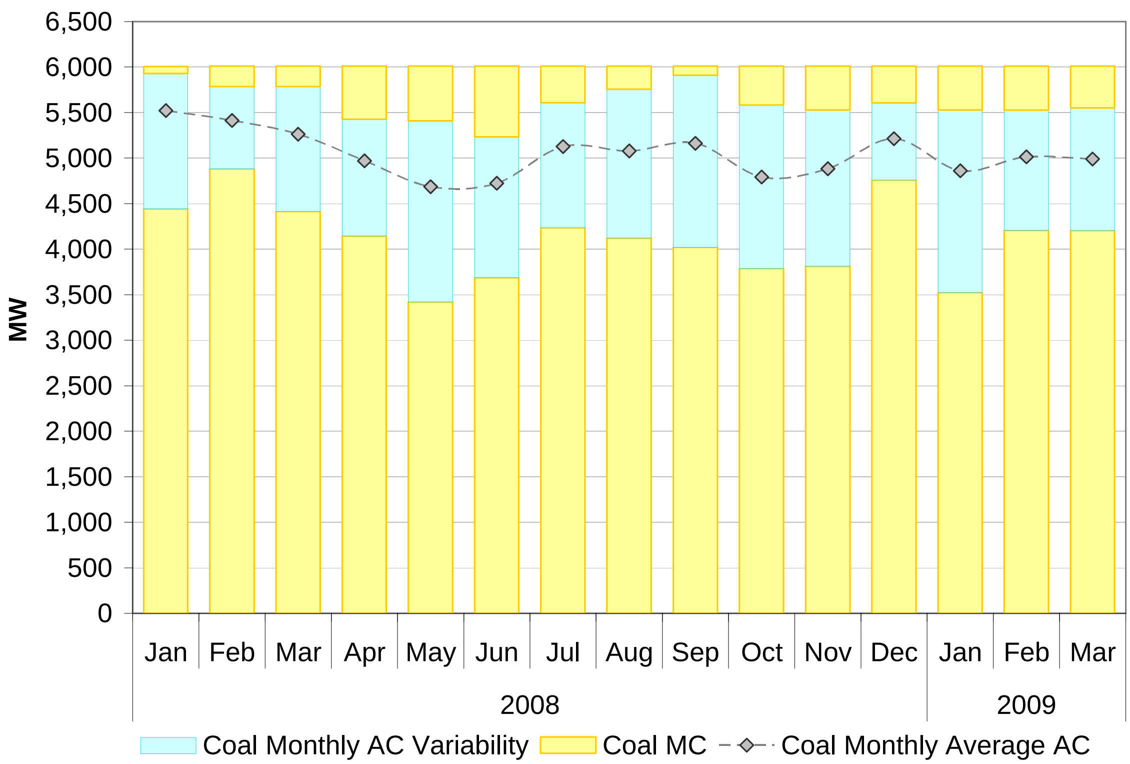
A year-over-year comparison of availability factors reveals a noteable decline for coal in Q1-09 (82%) as against Q1-08 (90%). While the availability of coal in Q1-09 was not far from the prior quarter, it is typically expected to be higher in the first quarter of a year, reflecting the recent completion of fall maintenance and absence of planned maintenance through the period of peak demand. This low availability factor was largely the result of a greater number of unplanned outages across much of the coal fleet. The drop in available capacity also manifests itself in a lower capacity factor of 78% in Q1-09, as against 86% in Q1-08. This decrease in generation is partly compensated for by the increased capacity factor of gas in the same quarter.

2.3 Availability of Coal-Fired Plant

A closer look at the availability of coal fired generation is presented in Figure vi which plots the MC, monthly average AC, and the monthly variability of AC. The seasonality of monthly average AC moves perdictably through the peak and shoulder seasons, with the exception of Jan-09 where average AC is some 600 MW less than a year earlier. The coal fleet's average AC improved marginally in February, and was essentially unchanged in March, but still underperformed against the same months in the prior year.

The variablility of coal AC is captured in the green band, which plots the minimum and maximum AC values observed in the given month. The width of this band tends to be greatest during the shoulder season, as would be expected during times when more maintenance is undertaken. A notable exception is again found in January-09 where the range of AC variabilty was 2005 MW, the largest in the 15 months under consideration. Some of the lowest values occurred in the period January 20-26 discussed in section 3.

Figure vi - Coal - Monthly Average MC, Monthly Average AC and Monthly AC Variability

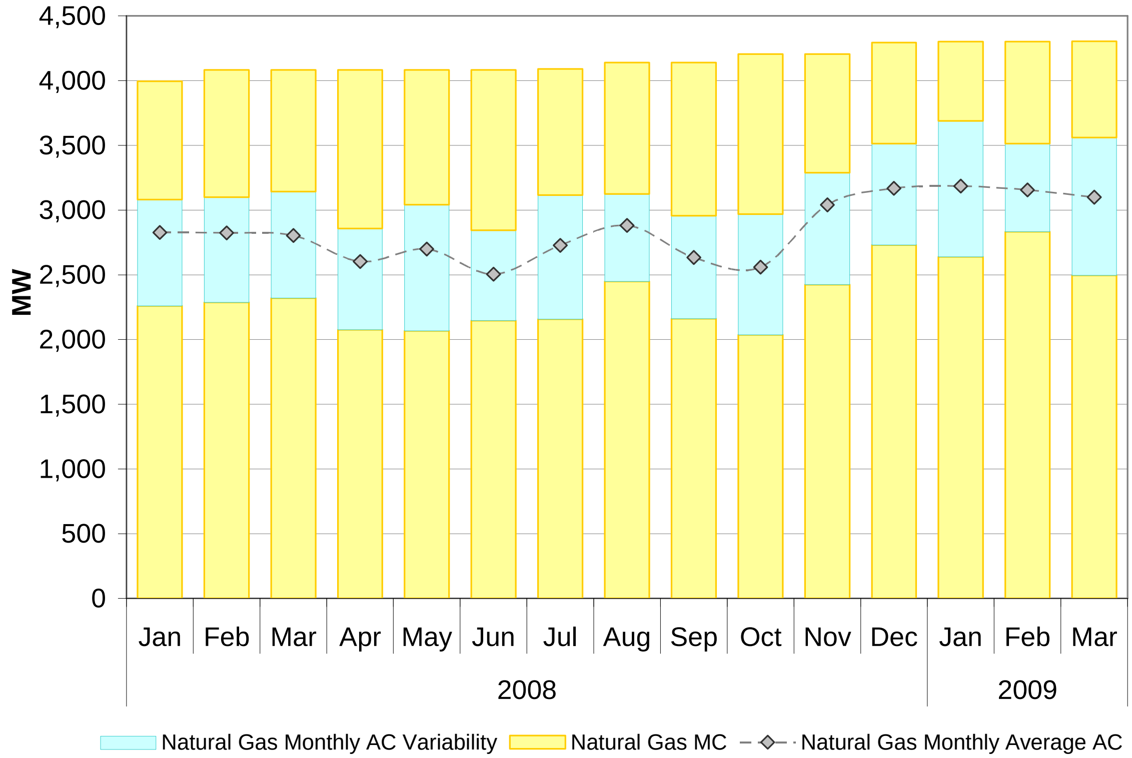


2.4 Availability of Natural Gas-Fired Plant

Figure vii presents the same perspective for the gas fleet. Over the past 15 months, gas MC increased by approximately 350 MW with the addition of new plants including: Nexen Inc # 2, Northern Prairie Power Project, CNRL Horizon, and Valley View 2.

The gas fleet's monthly average AC displays some of the seasonality expected, though the addition of new facilities, and more units over which planned maintenance is carried out, conceals the seasonality somewhat.

Figure vii - Natural Gas - Monthly Average MC, Monthly Average AC and Monthly AC Variability



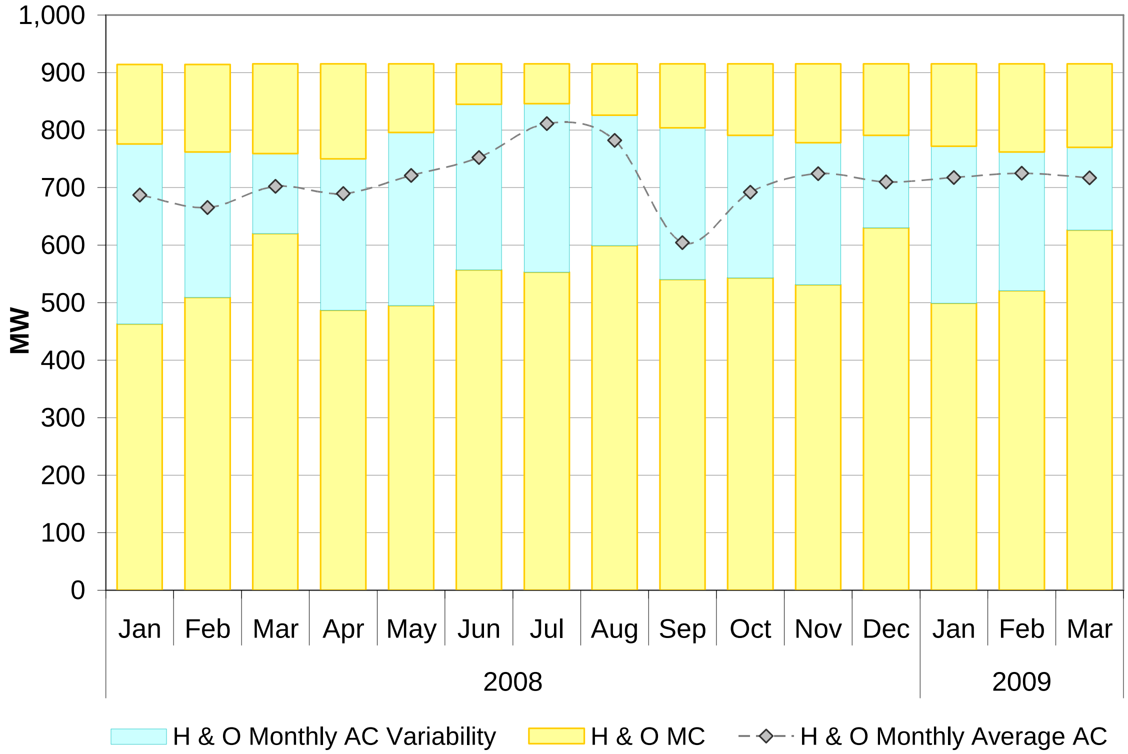
Gas AC variability tends to be more stable than coal. That is, the width of the band is both narrower, and more consistent. Another notable feature of the gas AC variability is that the range of AC values does not approach the MC limit, as is occasionally seen with coal. The combined impact on AC values of long-lead-time and cogen units within this fuel type contributes significantly to the persistence of this gap, making the comparison of MC and AC values a less reliable indicator of gas unit outages, than for coal units.

The stability of the AC values of the natural gas units relative to that of the coal fleet is not surprising. Most of the legacy PPA coal units are in the last 10 years of their book lives, whereas most of the natural gas units are in the first 10 years of theirs.

2.5 Availability of 'Hydro Plus Others'

Figure viii presents the same perspective for the combined hydro and other fuel types, where hydro constitutes the majority of capacity in that chart. Accordingly the visible patterns are attributable to the characteristics of hydro generation.

Figure viii - Hydro and Other - Monthly Average MC, Monthly Average AC and Monthly AC Variability



The MC is stable over the period of interest, and the monthly average AC varies seasonally, reflecting water conditions. The significant drop in average AC in September-08 was the result of maintenance at Brazeau.

2.6 Variability of Availability

The band of AC variability has a generally stable upper bound. The width of the band is not consistent, and in most months, the range of AC variability tends to lie mostly below the average AC. This characteristic is largely attributable to reservoir storage management, and other operational constraints facing the hydro system.

Table ii presents the variability of AC across fuel types for the quarters of interest. The variability of coal AC in Q1-09 was higher than Q1-08, which tends to agree with the lower availability factor for the quarter (see Table 1), coupled with the observation that there were more unplanned outages in the quarter than would typically be expected for that time of year.

Table ii - Quarterly AC Variability by Fuel Type

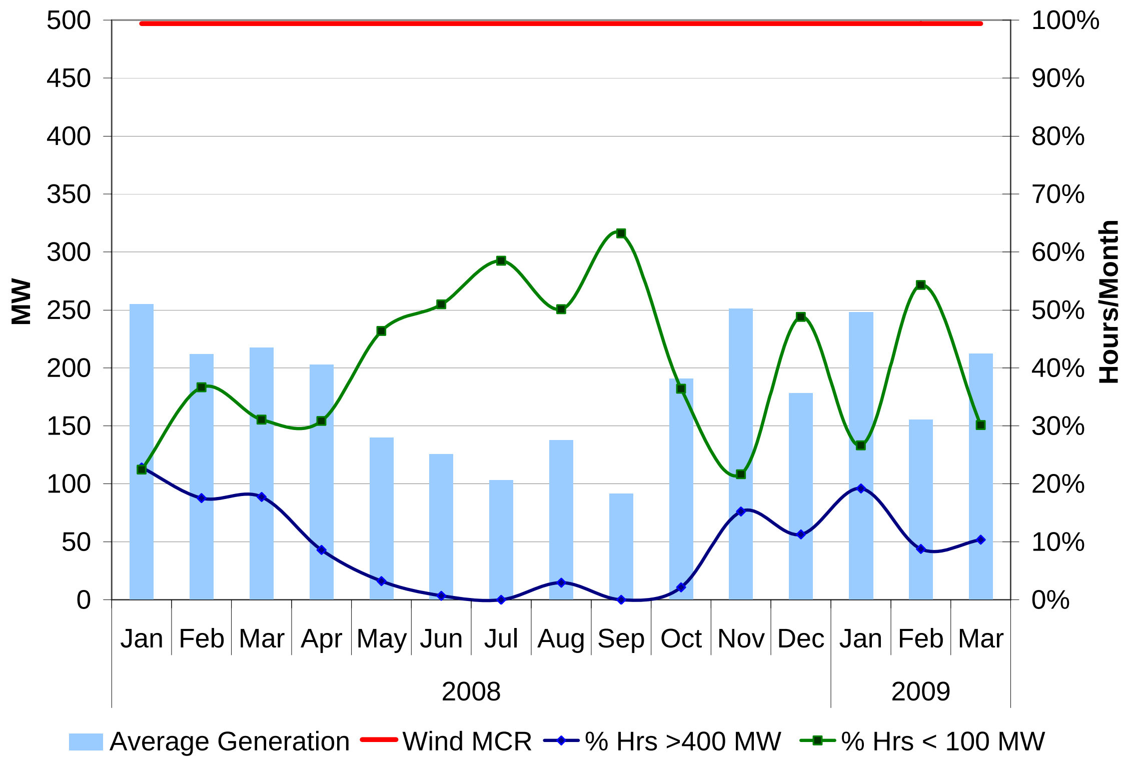
Fuel Type	Quarter	AC Variability (MW)	AC Variability (% of MC)
All Fuels	Q1/09	2284	20%
	Q4/08	2416	22%
	Q1/08	1882	17%
Coal	Q1/09	2,028	34%
	Q4/08	1,820	30%
	Q1/08	1,518	25%
Natural Gas	Q1/09	1,192	28%
	Q4/08	1,478	35%
	Q1/08	883	22%
Hydro & Other	Q1/09	294	32%
	Q4/08	278	30%
	Q1/08	313	34%

2.7 Wind Generation

Because wind generation does not offer into the merit order, it was excluded from the above analysis of MC and AC values. Wind generation is nonetheless an important consideration for the merit order and the market.

Figure ix plots the average hourly wind generation in each month, against the wind fleet's MCR of 497 MW, on the left axis. The percentage of hours in each month that wind generation is above 400 MW or below 100 MW is plotted on the right axis. It is instructive to think of these curves as the percentage of time that wind is having a relatively big presence (>400 MW) in the merit order, or a relatively small presence (<100MW).

Figure ix - Wind - Average Hourly Generation and MCR



Through the summer months, when wind generation is lowest, the percentage of hours in the month where generation exceeds 400 MW is at or near zero, whereas the number of hours where wind generation is less than 100 MW tends to be at or above 50%.

Table iii presents the wind fleet's MCR, total quarterly generation, and capacity factor for the respective quarter. The capacity factor for Q1-09 was down slightly, on account of lower generation in February.

Table iii - Wind Generation and Capacity Factor

Quarter	MCR [A]	Generation [B]	Capacity Factor [C]= [B]/([A]xhrs)
	(MW)	(MWh)	
Q1/09	497	447,124	42%
Q4/08	497	456,015	42%
Q1/08	497	499,309	46%

Table iii presents impressive capacity factors for wind generation. However, it is important to note that the quarters of interest are the periods of strongest wind production, and accordingly have the higher capacity factors. The capacity factor of Q2/08, for instance is approximately half that of Q4/08.

3 PRICE EVENT REPORT FOR JANUARY 20-26, 2009

3.1 Overview of the Event

Over the period January 21-23, 2009 the Alberta market experienced high daily average Pool prices of $282.87/MWh, $219.39/MWh and $624.94/MWh respectively. The January 23 average price of $624.94/MWh established a new record. These three days were part of a longer sequence of higher than usual price days spanning January 20 to 26. Note that no firm load was shed, although several times the merit order was exhausted and the appropriate emergency procedures were initiated by the ISO. This is primarily a market event, rather than reliability, and that is the focus of this report.

In February, the MSA received a complaint from several representatives of load organizations. One of the main concerns expressed in their letter of complaint was about the pricing on these days and whether they were the result of a true scarcity situation. This report has been prepared in part to address this concern.

The average Pool price over the period January 20 to 26 was $216.76/MWh which is less than the highest 7-day average last year at $239.73/MWh from April 4 - 10. The record highest 7-day sequences since 2001 are as shown in Table 1.

Table iv - Record 7-Day Price Events

Rank	Dates of Occurrence	Average Price ($/MWh)
1	October 3 - 9, 2006	329.30
2	July 21- 27, 2006	320.09
3	July 11 - 17, 2007	270.35
4	July 23 - 29, 2007	248.10
5	April 4 - 10, 2008	239.73
6	**January 20 - 26, 2009**	**216.76**
7	September 28 - October 4, 2006	210.77
8	January 19 - 25, 2001	182.54
9	November 19 - 25, 2005	178.64
10	October 9 - 15, 2008	177.48

Notwithstanding this significant price event, the year-to-date Pool price stands below $60/MWh as of late April.

The prices over the latter part of January were high and warranted an assessment as to whether they appropriately represented scarcity or were the result of other factors.

Previous experience based on observation and analysis of the Alberta market shows that some of the key factors influencing short-term Pool price increases are:

- Load (Demand);
- Intertie import availability;
- Wind generation; and,
- Unit outages – particularly baseload units.

The above items cover the most important 'volumetric' parameters and are discussed in the following sections. Figure x shows all these parameters except intertie availability (which did not vary much during the week).

3.1.1 Load

January is a winter month and accordingly experiences high loads. The average over January 20-26 was 8569 MW which is a little higher than the average value for the whole of January (8442 MW). In terms of peak hourly values each day, the average over January 20-26 was 9282 MW, very close to that over the whole month (9224 MW). The variability of load across the days was a factor with about 600 MW as the range between the lowest and highest daily averages.

3.1.2 Intertie Import Availability

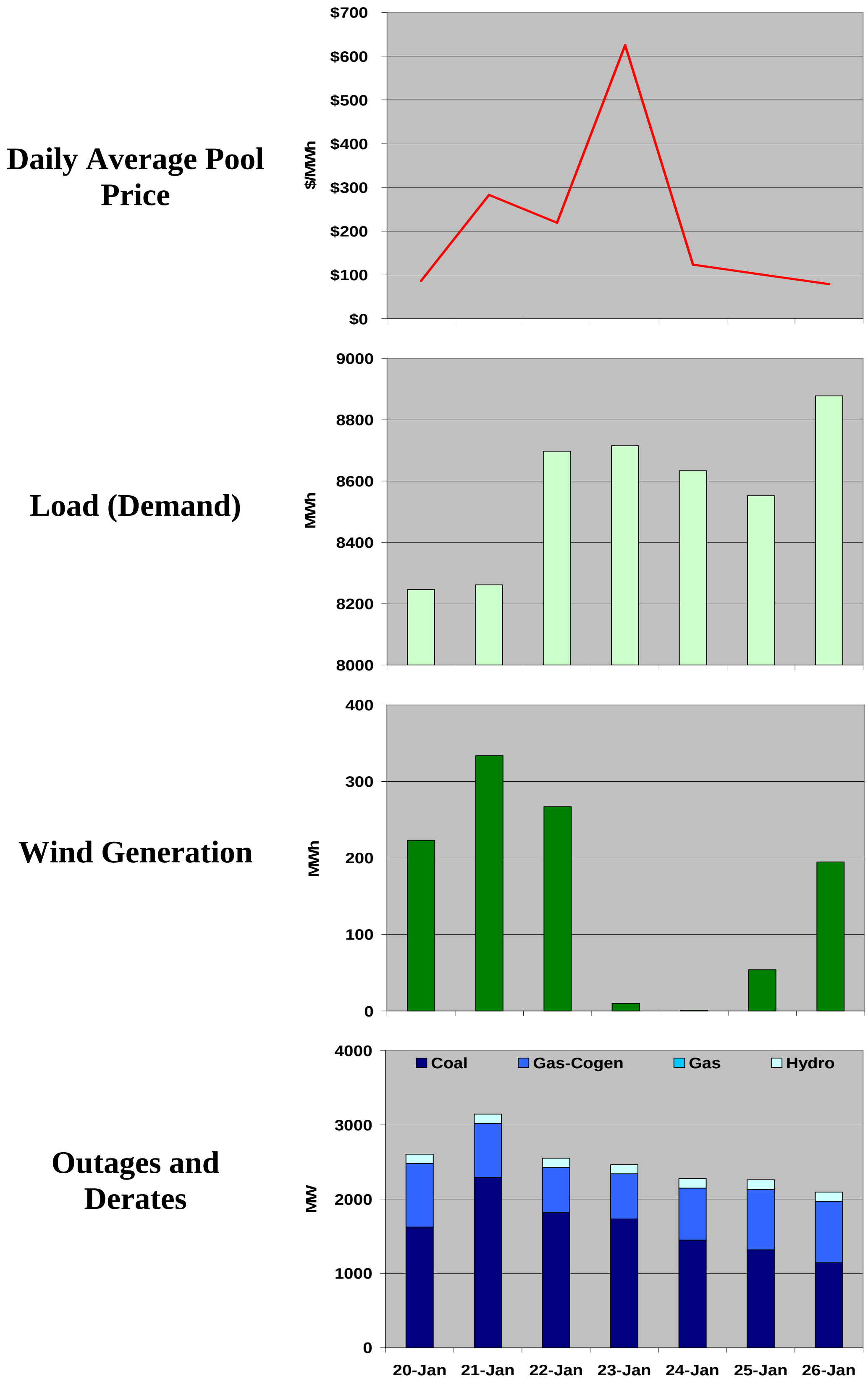
Intertie availability for imports from both BC and Saskatchewan was high over the period of interest and average hourly Available Transfer Capability (ATC) was 665 MW. Import ATC ranged from 652 MW to 673 MW. Prices in Alberta higher than those in the surrounding markets signal imports, and participants respond to the opportunity. Price events in the past have often been influenced by maintenance work on the interties that limited imports, but this was not the case here. The restrictions imposed by the (T-2) offer rules do mean that the interties are not always fully loaded when short-term price excursions occur.

3.1.3 Wind Generation

Over the past several years, wind has become a new dynamic in the market that has a tremendous impact on Pool prices and, potentially, the offer behaviour of other generators in the system. With about 500 MW in the system at present, much of it in the same general part of Alberta and subject to coincident airflow patterns, its generation on windy days is like that of a large baseload unit that can not/will not respond to price, and on calm days its generation is like that of a large baseload unit on maintenance. Add in its relative unpredictability and it is easy to appreciate why wind has an effect on Pool prices.

Over the period of interest, the average amount of wind generation was 155 MW, lower than the 250 MW applicable for the whole month of January. However, again it is the variability both across the days and within the days that affects the market most directly – ranging from essentially 0 MW to over 300 MW daily average values.

Figure x - Average Daily Pool Price, Demand, Wind and Outages, Jan. 20-26



3.1.4 Unit Outages and Derates

The availability of coal plant (baseload) has long been a primary driver of short-term Pool prices. January usually has limited planned maintenance for coal units and over the period January 20-26 only Sheerness #2 and Sundance #1 were on planned maintenance.

However, there were a number of forced outages and derates, key among them being Sundance #3, Sundance #4, Sundance #6, Keephills #1 and Wabamun #4.

Overall, outages and derates at coal units averaged 1630 MW over the period January 20-26 which is more than 25% of the coal fleet's capacity and is an exceptionally high amount of outage for January. Also, the variability of coal outages during the event is significant.

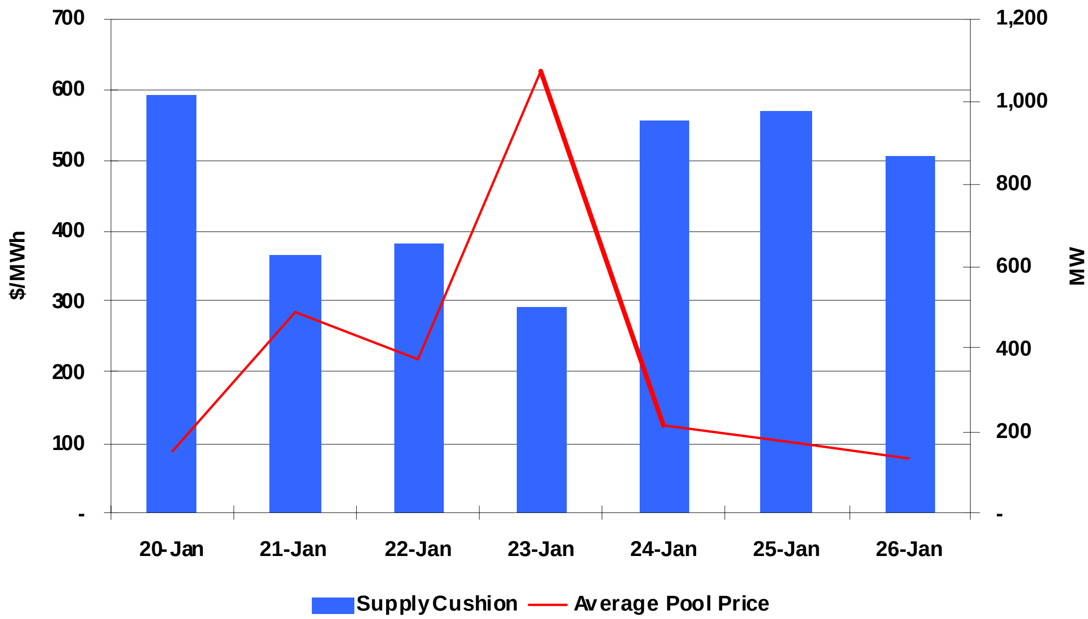
3.1.5 Supply Cushion

There are days when the load may be quite high, with lots of outages and derates at the plants, the wind is not blowing much for the wind generators and import capacity is low because of maintenance. In such situations the supply cushion is low and Pool prices tend to be high. On other days, the load may be low, the generation fleet is healthy, wind generation is robust and the intertie is fully available. The prices then tend to be much lower with the increased cushion. Usually, most days are somewhere in between.

The supply cushion is simply the undispatched MW in the merit order that the System Controllers could have used if necessary, but did not have to actually call on.

Figure xi displays the daily average supply cushion and average Pool price. The relationship is quite distinct in that the highest daily average prices correspond to the lowest supply cushion values and is the expected outcome.

Figure xi - Average Daily Supply Cushion and Pool Price, Jan. 20-26



It seems that the range in supply cushion values of January 21-23 is moderate yet the variability of the daily average Pool prices is not. Both the supply cushion and Pool price vary considerably throughout the day and using the daily average values might be somewhat misleading. Similarly, the relationship between supply cushion and Pool price might be nonlinear. A small change in supply cushion, when the supply cushion is low, might lead to a considerably different response in Pool price than at higher levels of supply cushion. Finally, of course, the offer behaviour of market participants plays a role in setting Pool price and this may have changed over the course of the three days.

For the balance of this report, attention will focus on the three days January 21-23 which contained the highest prices.

3.2 Detailed Assessment of January 21-23, 2009

The hourly supply cushion and corresponding Pool prices are presented on Figure 3. It is apparent that generally the supply cushion for each day is greatest in the overnight period when the load is lowest. Also, the corresponding Pool prices are lower at these times.

Figure xiii shows the same data in the form of a scatter plot of the hourly values of supply cushion and corresponding Pool price for each of the three days. Again it is apparent that there is a high degree of correspondence between high values of supply cushion and lower Pool prices. In this figure, it is more readily seen that the circumstances of January 23 appear different from the other two days in that for the same amount of supply cushion the Pool price is higher.

It needs to be acknowledged that the supply curve in Alberta (the stack of offers from the generators ranked from lowest to highest price) is very steep at the upper end meaning that the rate of increase in price per MW of supply is larger. When the supply cushion is small, the applicable part of the supply curve is steep. At a price level of $40 to $50/MWh, a decrease in supply cushion of 100 MW might cause price to move up by only $1 or $2/MWh. Nearer the top of the stack, when the supply cushion is small, that same decrease might move up the price by $100 to $200/MWh, or even more.

Figures xii and xiii serve to confirm that there is a solid logical relationship between supply cushion and Pool price. It also confirms that the relationship is nonlinear and in the form one might anticipate.

Overall, the relationship on January 23 appears different from that on January 21 and 22 and the analysis now focuses participant offer behaviour.

Figure xii - Supply Cushion and Pool Prices, Jan. 21-23

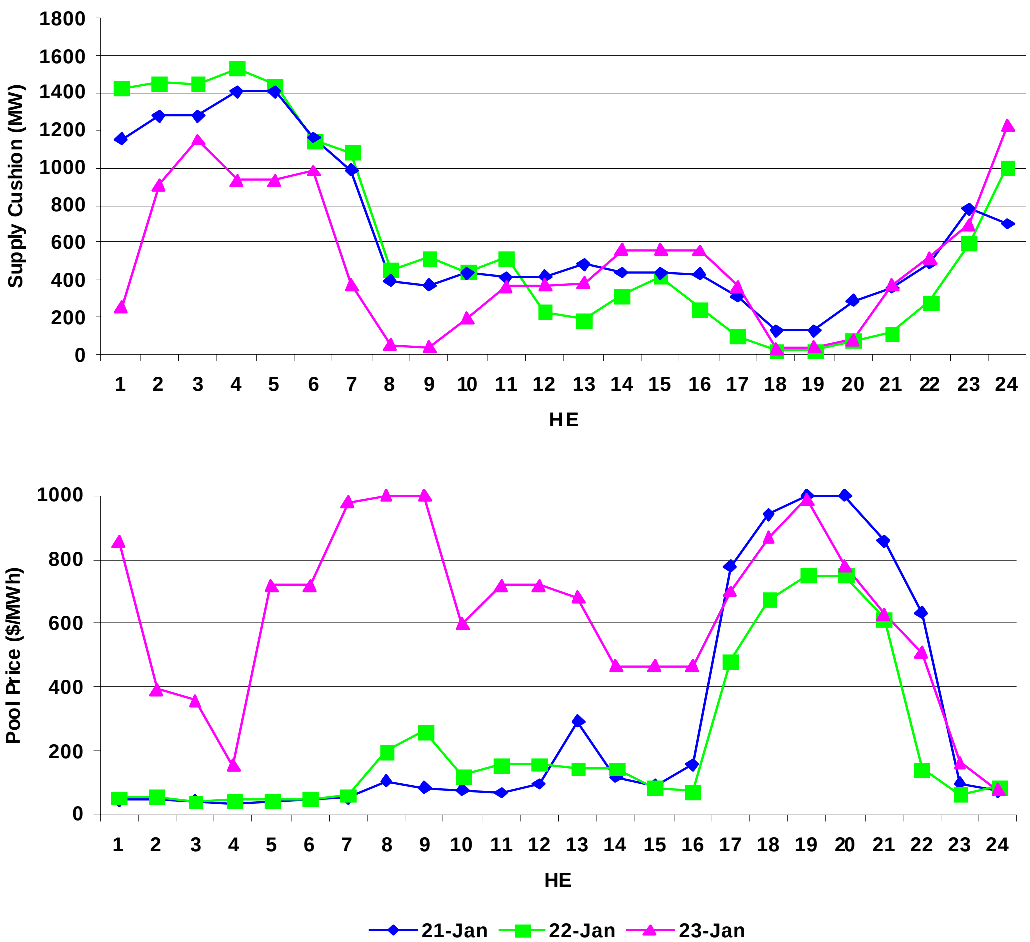
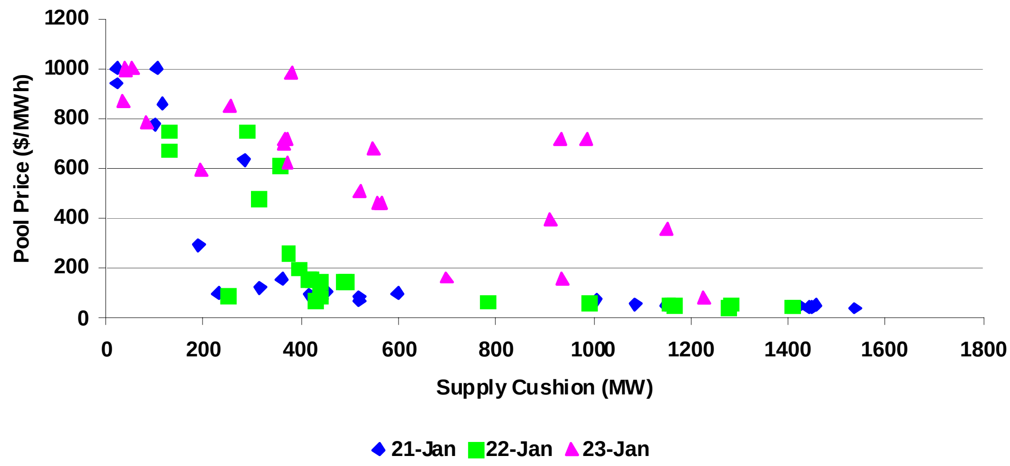


Figure xiii - Scatter Plot of Supply Cushion and Pool Prices, Jan. 21-23



3.2.1 Analysis of Offer Behaviour

Analysis of the offers of all assets in the merit order was undertaken for the three days, and, where warranted, over longer periods of time. The objective of the analysis was to determine to what extent changing generator offer strategies played a role in the determination of Pool price, and the seeming differences from one day to the next.

For most of the generating units, the primary differences in offers to the market are related to the following factors:

- Availability to run;
- Differences in offer strategies between on-peak and off-peak hours;
- 'Pricing up' in some tight hours by participants; and,
- Changes in offers driven by portfolio strategies.

3.2.2 Availability to Run

This is fairly straightforward in that on those occasions when a unit was on maintenance it cannot offer energy to the market. The MSA is keenly aware that physical withholding, meaning the false declaration of plant outage to the AESO, could be a profitable strategy for a plant owner. We have no evidence to suggest that this occurred on the days in question.

3.2.3 On-Peak to Off-Peak Strategies

Some generating assets have different sets of offers and volumes that correspond closely with the on-peak and off-peak hours of the day and participation in the operating reserves market.

In some cases, such as hydro, the differences are more to do with changes in physical or environmental constraints than actual ‘strategy’ as such. In any event, energy limited generation like hydro needs to be strategic in its offers.

For the remainder of the thermal generators, the change appears to be in response to the general supply cushion situation. Overnight the supply cushion is higher and competition among the low-cost generators ‘forces’ some to lower their offers to avoid being idled. Some of the fiercest competition amongst the generators is observable in the low load hours as they jockey for the right to run. In the on-peak hours, these low-cost generators will then attempt to raise their prices by shadowing more expensive offers.

For the high-cost generators that change their strategy between on- and off-peak, they tend to do so by pricing higher in the off-peak period. This may seem surprising at first glance, but is quite rational in response to the greater supply cushion. Essentially, these assets are locked out of the market unless something unforeseen occurs – typically the loss of a generating unit or the unexpected ramping down of wind generation. Any price excursions that would lead to them being in merit would likely not be long in duration and this must be factored into the generator’s offer price.

3.2.4 Pricing Up Behaviour

The term ‘pricing up’ refers to energy from an asset that is offered to the market at an increased price when there appears to be no cost-based reason for the increase. Such actions are not against any ISO rule provided the participant follows normal ISO offer protocols.

The analysis of the assets that are not part of a larger portfolio revealed that they did not engage in any significant amount of pricing up in response to the market tightness.

3.2.5 Portfolio Offer Strategies

Some of the larger portfolio generators in Alberta engage in what is commonly termed ‘portfolio offering’. This describes the situation where individual assets within a portfolio are not optimized in a stand-alone fashion but as a conglomerate, to benefit the portfolio as a whole.

The result is that when the portfolio is short, meaning that forward sales are more than physical generation in the portfolio, all assets are offered at close to variable costs. In such cases, the generator wants his fleet producing energy to cover his forward sales. When the portfolio is long and generation in the portfolio exceeds forward sales, the generator has choices with regard to the excess capacity that is not sold forward. Some generators elect to price most of the excess energy at very high prices taking on dispatch risk in return for possibly enhanced Pool prices.

This activity is not adopted by all portfolio owners, nor is it against any ISO rules.

3.2.6 Effect of Offer Behaviour

The MSA's analysis revealed that the offer strategy that most affected Pool prices over the period January 21-23 was the portfolio offer behaviour. On January 21 and 22, two participants appear to have been short in real time and offered all available energy at close to variable cost. On January 23, both appeared to be long in the market (due to units returning from outage) and offered their surplus energy at very high prices. This is entirely consistent with their normal offer strategy. However, the effect on prices is seen in contributing to the difference between the average prices of January 21-22 and January 23. If the two participants had remained short on January 23, likely the average price that day would have been much closer to $400/MWh. Similarly, if they had been long on January 21-22, average prices would have been substantially higher. One of the outcomes of the portfolio offer strategy is that the offer prices of some of the assets in the portfolio will fluctuate significantly and affect Pool prices, as was the case over these three days.

3.3 Conclusion

Analysis of the data has shown that the market was particularly tight over the three days, January 21-23, and it is not surprising that these are the three highest price days in the period. The three days had quite different average prices, ranging from $219.39/MWh to $624.94/MWh. The supply cushions for the three days were quite similar, although the lowest value did occur on the highest price day.

It needs to be acknowledged that the supply curve in Alberta (the stack of offers from the generators ranked from lowest to highest price) is very steep at the upper end. At the lowest values of supply cushion, modest changes lead to dramatic changes in Pool prices. Thus, some of the Pool price differences were caused by the modest differences in supply cushion and occurred in a logical way (i.e. the ranking of the average Pool prices was the reverse of that of the supply cushions)

No generators appear to have taken the opportunity to 'price up' during this event. Note that such action would not be a breach of ISO rules.

Portfolio offers by participants was a significant factor in the price outcomes. Such activity is not against ISO rules. The portfolio offer strategy was consistent with previous offer behaviour and not opportunistic in terms of taking advantage of the particular tightness in the market. At the present time, the MSA has not come to a final view on whether portfolio offers are a necessary component of a well functioning energy-only market such as the one we have here in Alberta.

Assessment of generator offer behaviour is an ongoing activity for the MSA. Distinguishing between genuine scarcity prices and the exercise (and possibly abuse) of market power in an hourly market is a difficult task. Genuine scarcity prices are the mechanism through which investors in generation receive an important portion of their returns. It is also the mechanism which sends the build signal for new generation. The market price is more vulnerable to manipulation in tight conditions than when supply surplus is plentiful. Also the market becomes more susceptible to portfolio offer strategies of participants that control larger fraction of the total market supply.

Currently, there is no holding restriction in the Alberta market. There is a possibility that the government will impose a restriction on size, but the level is likely quite high. To the extent that participants are able to grow larger in size, consideration needs to be made of some form of limitation on their offer behaviour, given how much this can affect Pool prices.

In the next few months, we plan to engage Alberta stakeholders through our written stakeholder consultation process to develop guidance to the market on what is, and is not, acceptable offer behaviour in the Alberta market. Our hope is that all participants will assist us in this important endeavor. The first stage of this work is a 'filtering' exercise in which the MSA engages in bilateral discussions with participants to solicit views and ideas. Should you wish to engage in this part of the work please Matt Ayres at 403-705-3182 or matt.ayres@albertamsa.ca

4 ISO RULES COMPLIANCE UPDATE

The MSA continues its work on ISO Rules Compliance. Table v provides an update as of the end of Q1/09. During Q1/09, 12 notices of specified penalty have been issued, in 6 other instances the MSA chose to forbear, and 5 matters referred to the MSA in Q1/09 remained under review.

Table v - Q1/09 Compliance Files

ISO Rule	Under review	Notice of Specified Penalty	Forbearance
3.5.3.2	0	3	0
6.3.3	0	2	0
6.4.3	0	0	1
6.5.3	3	0	2
6.6	1	7	3
9.1.5	1	0	0
Total	5	12	6

Some of the files included in Table v include matters the have come to the MSA's attention through self reports. Some market participants have asked how long they have to self report potential breaches. The MSA has taken the approach that self reports can occur at any time prior to being made aware by the AESO or through our own monitoring of potential non compliance. Self reports do not necessarily result in the issuance of a specified penalty. In some cases where there are mitigating circumstances the MSA has chosen not to pursue a self report of a potential non-compliance event. We encourage all market participants that self report to provide all relevant information related to the event in order to assist our investigation.

Not all of the rules in Table v are included in the specified penalty categories of AUC Rule 19, i.e. there is no specified penalty for contraventions of these rules. If the MSA chooses to pursue these rules it must do so under Section 51 of the Alberta Utilities Commission Act which will result in a hearing or other proceeding even in the event the contravention is not contested. In the interests of administrative efficiency 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. The MSA is aware that Rule 19 may need to be revisited following the revision to ISO Rule 6.6 and consequently believes it is sensible to delay a request to revisit Rule 19 at this time.

4.1 Emerging non-Compliance Trends

To assist market participants in complying with ISO rules, the MSA intends to report on some emerging trends in potential non-compliance. Note that this is intended as an early indicator, and does not necessarily imply that referrals have been made to the AESO to the MSA or that enforcement action is pending. The MSA suggests participants may wish to review their training and compliance procedures in these areas:

OPP 102 & OPP 003.2 - possible contraventions detected where a market participant is either not logged into the Automated Dispatch and Messaging System (ADAMS) or otherwise fails to respond to a dispatch within the required two minute period.

6.3.3 - possible contraventions detected whereby market participants have restated their Available Capability (AC) for an import or export without an acceptable operational reason.

6.5.3 – This ISO rule relates to expectations around the provision of ancillary services. Possible contraventions relate to situations where subsequent to receiving a directive for spinning or supplemental reserves not of all the MW have been provided within 10 minutes.

9.1.5 - This ISO rule relates to project material procurement by a transmission facility owner. Possible contraventions relate to the rule's particular requirements for record keeping and retention.

5 MSA ACTIVITIES

5.1 Spring Stakeholder Meetings

The MSA held its annual spring Stakeholder meeting in Calgary on March 18th. The Edmonton Stakeholder meeting scheduled for March 17th was cancelled due to the low numbers anticipated to attend. The MSA will continue to canvass the interest in having future stakeholder meetings in Edmonton, and should the numbers warrant a stakeholder meeting in that city we will be glad to do so. A copy of the slides from the March 18th stakeholder meeting is on the MSA's website at http://www.albertamsa.ca/files/Spring_Stakeholder_Meeting_031809.pdf.

5.2 EISG

The MSA was represented at the recent spring conference of the Energy Inter-Market Surveillance Group – an association of electricity market monitoring groups in other jurisdictions in North America and abroad. This group meets on a semi-annual basis to review and discuss matters of mutual interest regarding monitoring of competitive electricity markets.

5.3 Retail Review: Electricity & Natural Gas Report

In February the MSA published a review of Alberta's electricity and natural gas retail markets. In addition to updated metrics on switching from regulated to competitive electricity products, the report also contained new metrics: switching in the natural gas retail market, the prevalence of duel fuel products, and 'green' electricity products.

5.4 AUC Proceedings

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

- **Proceeding 115 –** Application by the Market Surveillance Adminstrator (MSA) and Syncrude Canada Ltd. (Syncrude) for a determination with respect to the Late Payment of a Specified Penalty – Within Consent Order M2009-001, Syncrude was ordered to pay the amount equal to the interest accrued on the Specified Penalty between July 2, 2008 and July 18, 2008.
- **Proceeding 168** - Confirmation of a Specified Penalty issued to Syncrude Canada Ltd **–** An oral hearing for this proceeding is set for May 27, 2009.

5.5 New Staff

In March, Jeff Crozier joined the MSA analytical team. He has a Masters degree in economics and prior experience in consulting and working at the NEB.

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]
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%**
Oct-08	100.51	137.34	49.52	159.73	159%
Nov-08	96.66	127.27	58.52	159.75	165%
Dec-08	88.36	99.53	72.89	132.02	149%
Q4-2008	**95.16**	**121.23**	**60.29**	**150.99**	**159%**
Jan-08	80.30	98.56	55.02	96.23	120%
Feb-08	64.89	74.99	51.24	38.31	59%
Mar-08	84.89	99.51	66.30	90.37	106%
Q1-08	**76.95**	**91.32**	**57.77**	**80.43**	**105%**

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

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

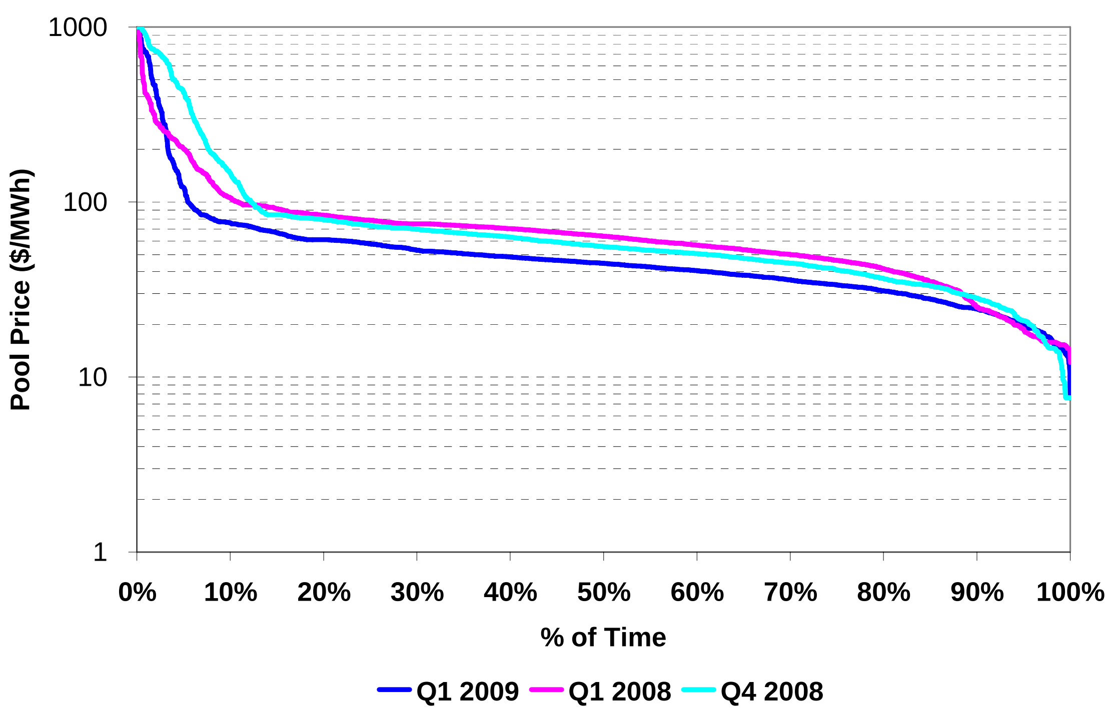


Figure 2 - Pool Price with Pool Price Volatility

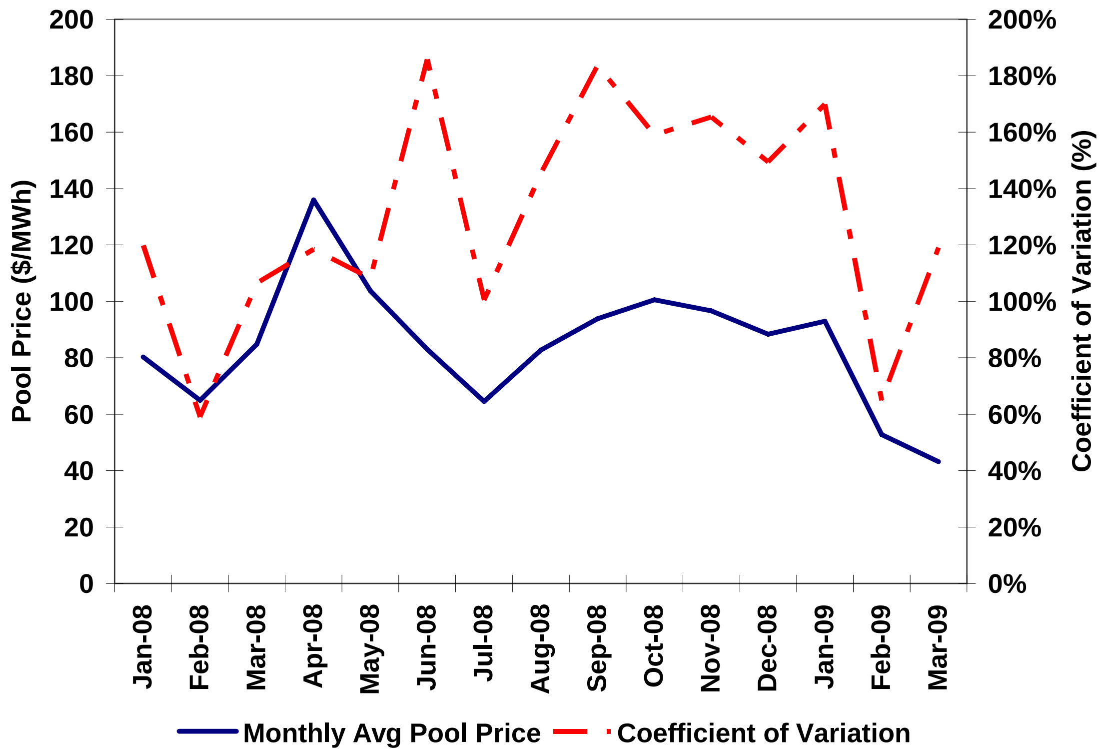


Figure 3 - Pool Price with AECO Gas Price

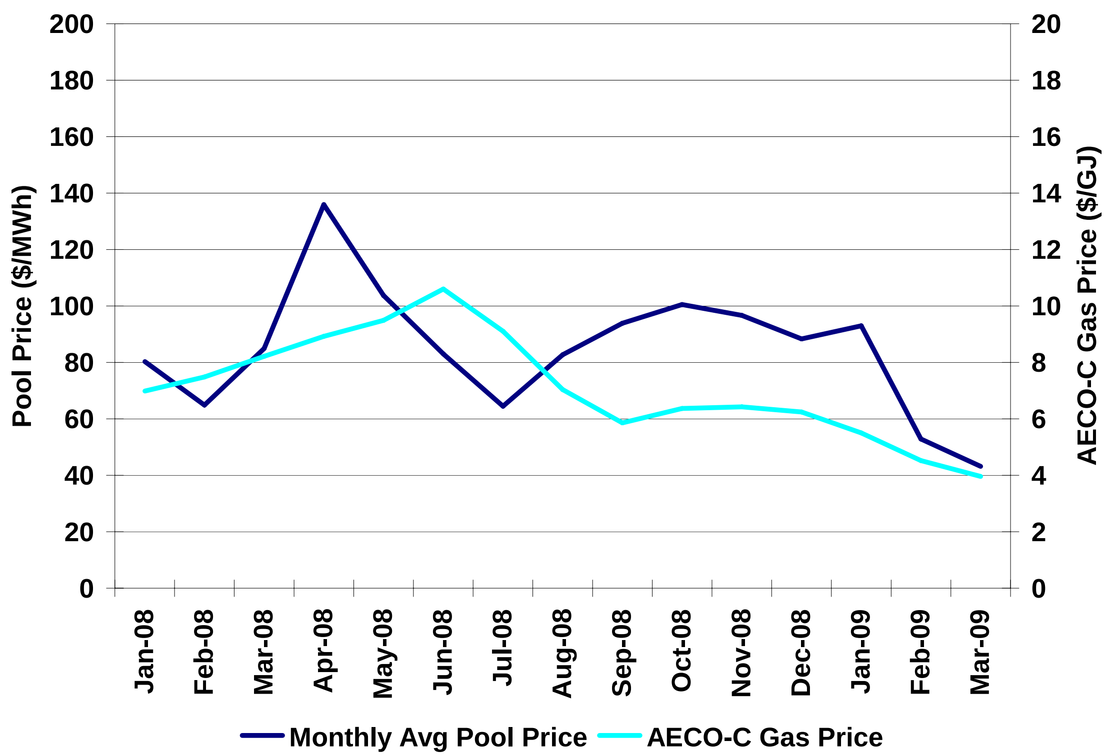


Figure 4 - Price Setters by Pool Participant (All Hours)

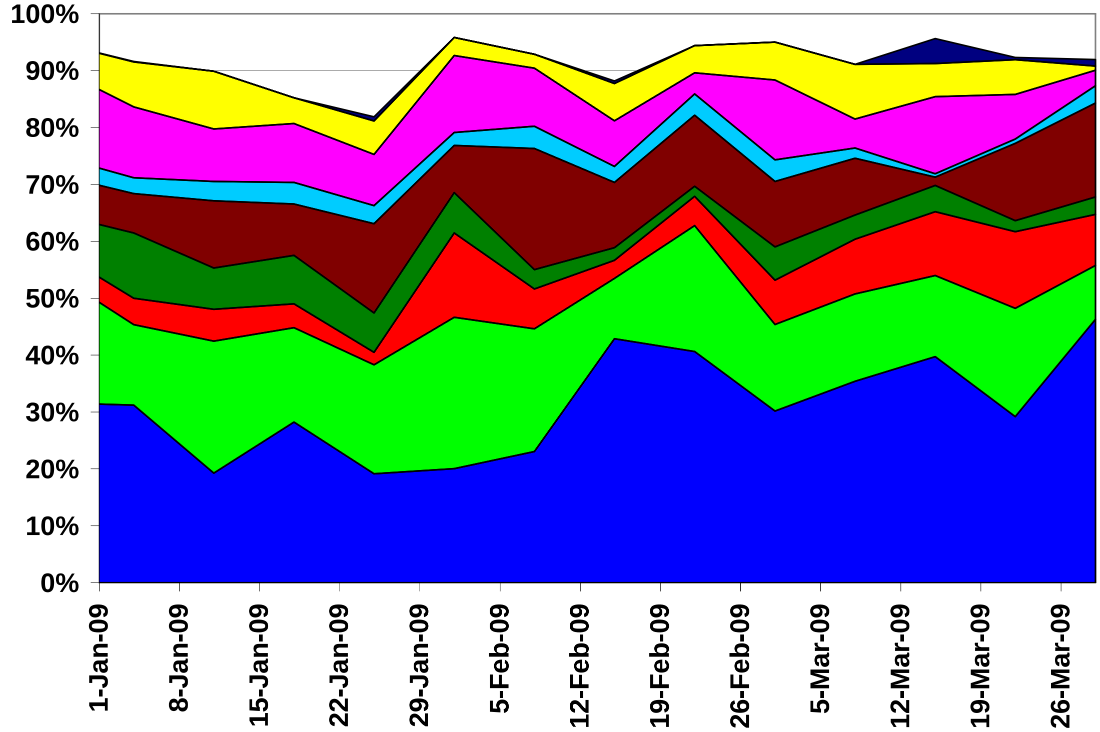


Figure 5 - Price Setters by Fuel Type (All Hours)

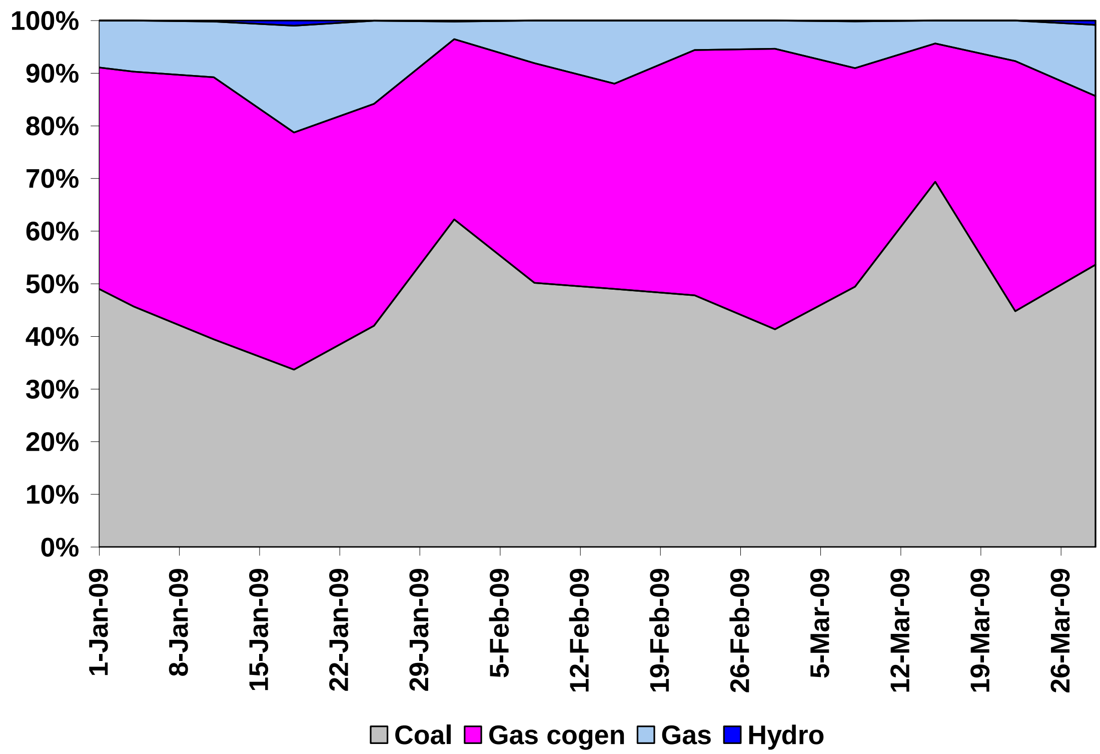


Figure 6 - Heat Rate Duration Curves (All Hours)

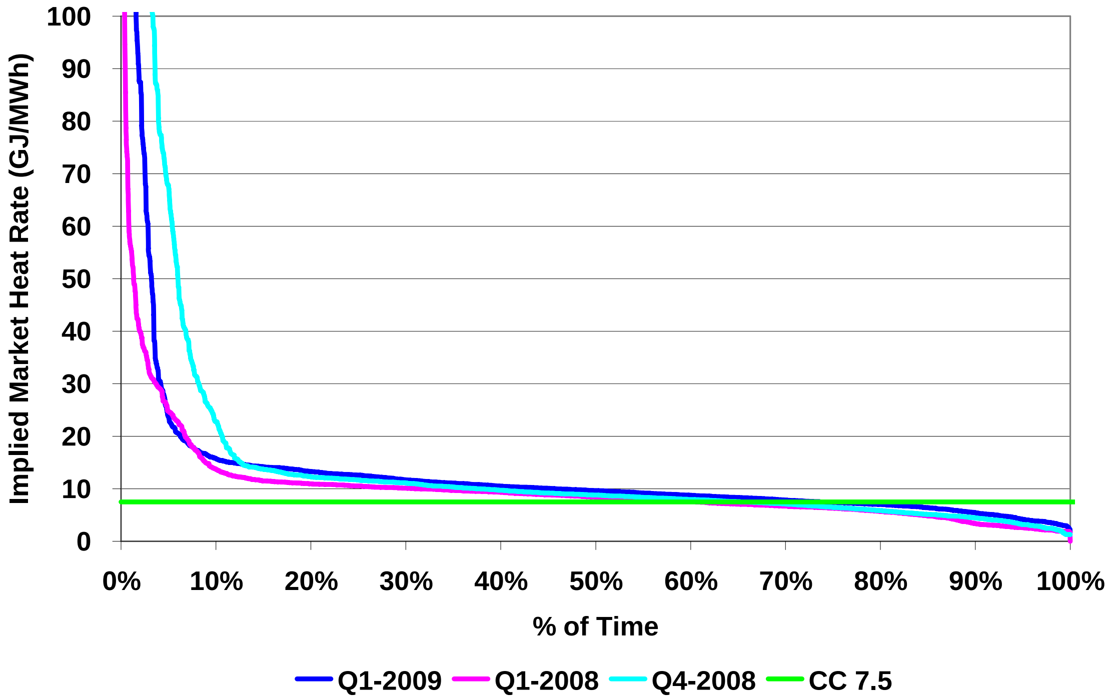


Figure 7 - Implied Market Heat Rates On-Peak

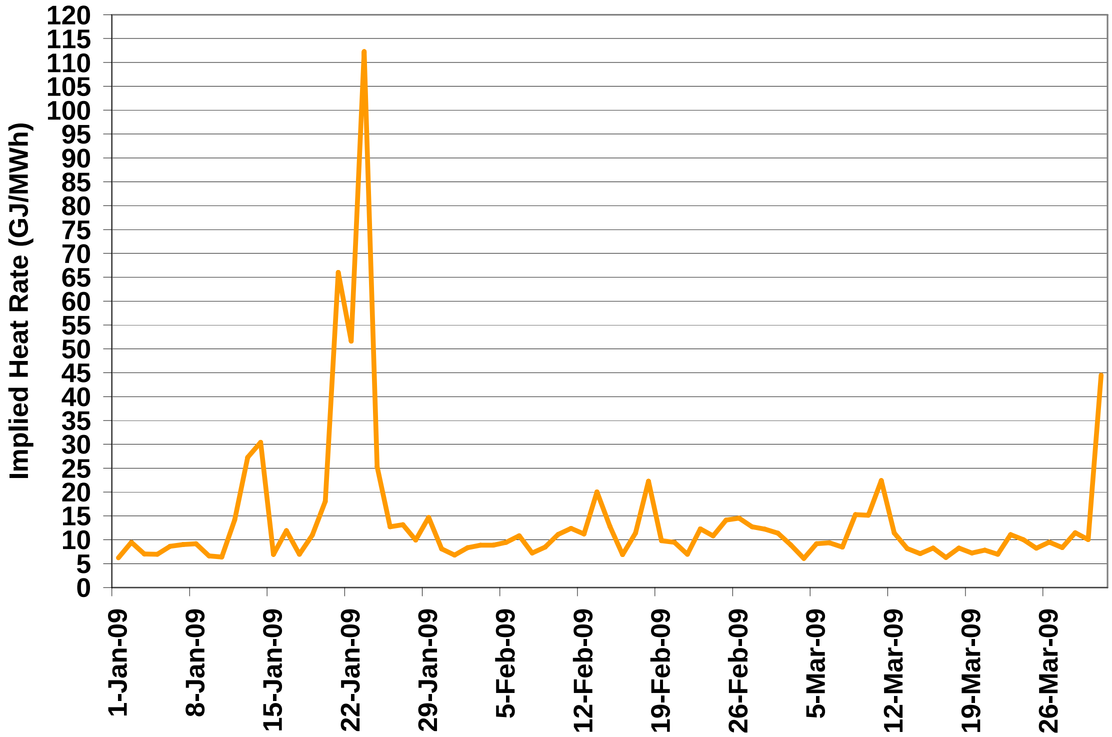
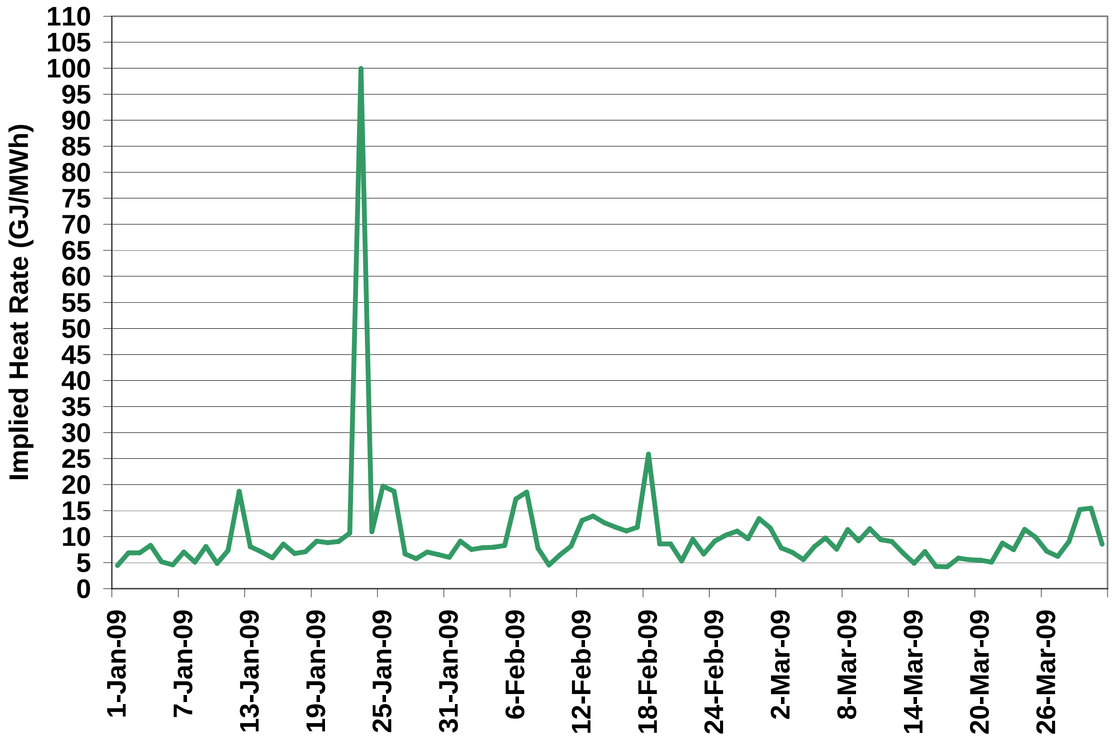


Figure 8 - Implied Market Heat Rates Off-Peak

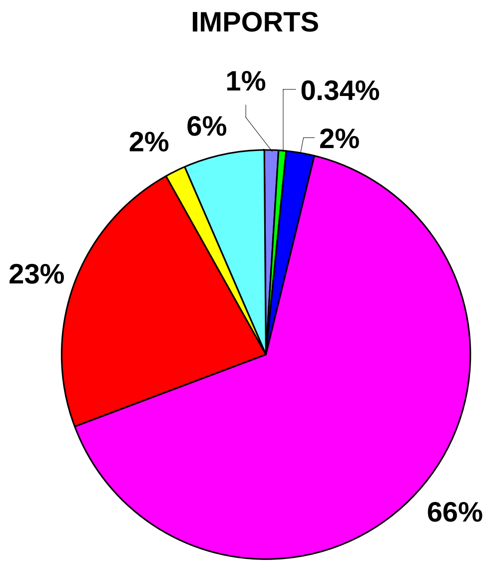


APPENDIX B – INTERTIE STATISTICS

Table 2 - 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)
Jan-09	206,649	41,613	165,036	56,144	1,597	54,547	262,793	43,210	219,583
Feb-09	162,330	46,952	115,378	53,492	950	52,542	215,822	47,902	167,920
Mar-09	158,586	32,162	126,424	32,345	4,545	27,800	190,931	36,707	154,224
Q1-2009	527,565	120,727	406,838	141,981	7,092	134,889	669,546	127,819	541,727

Figure 9 - Market Share of Importers and Exporters



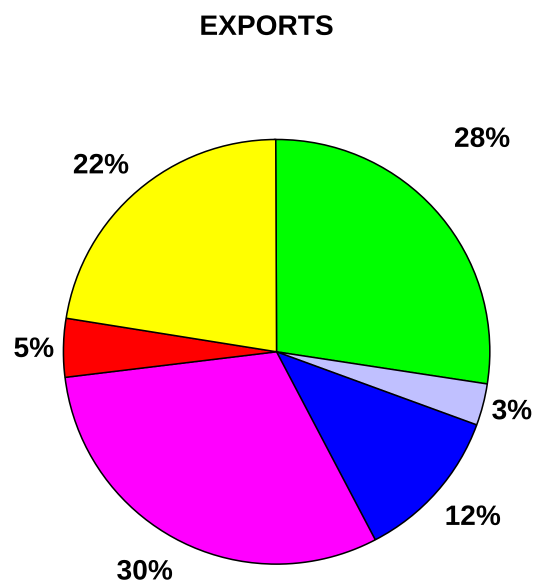


Figure 10 - Intertie Utilization Q1/09

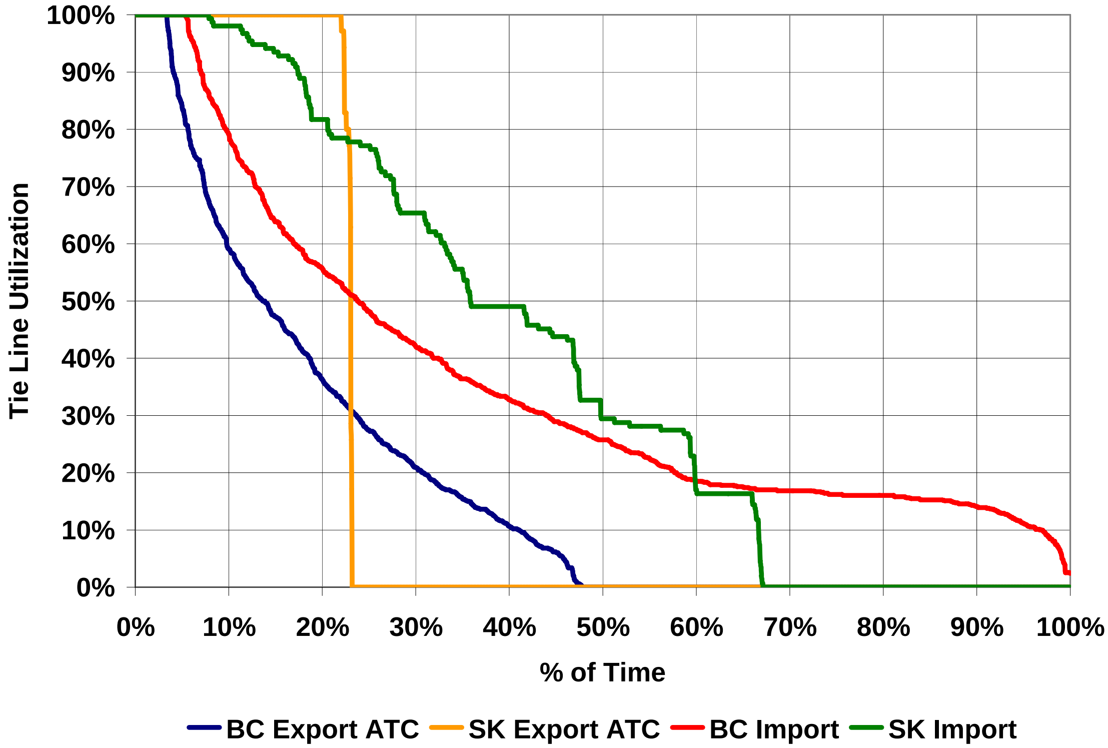


Figure 11 - Imports with Trade-weighted Prices

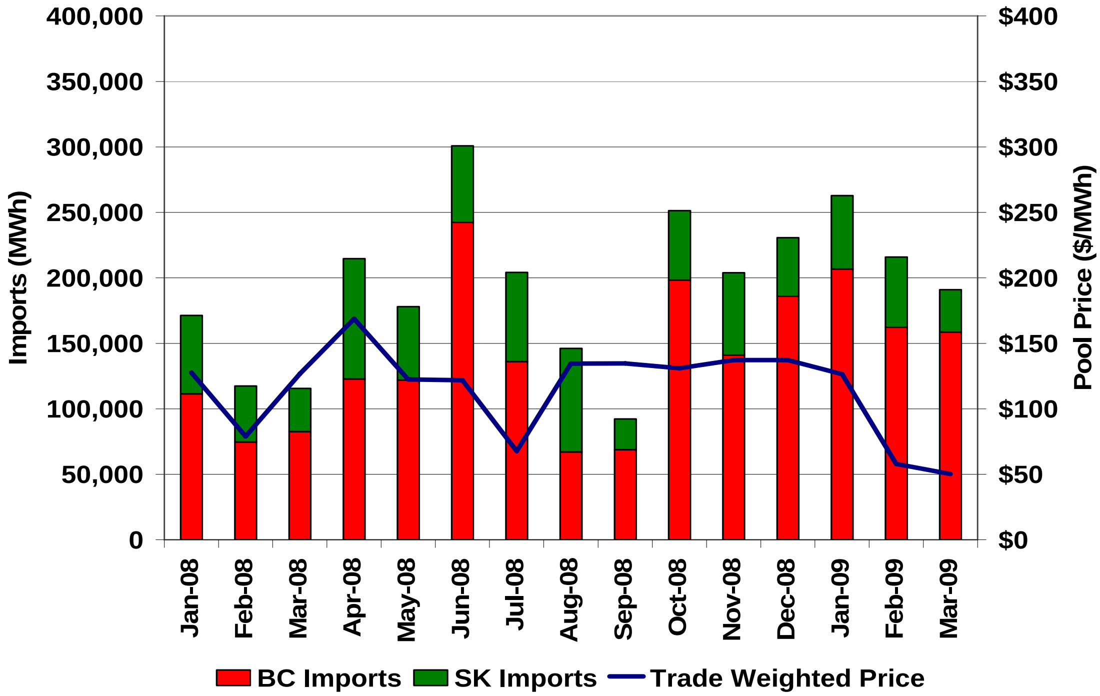


Figure 12 - Exports with Trade-weighted Prices

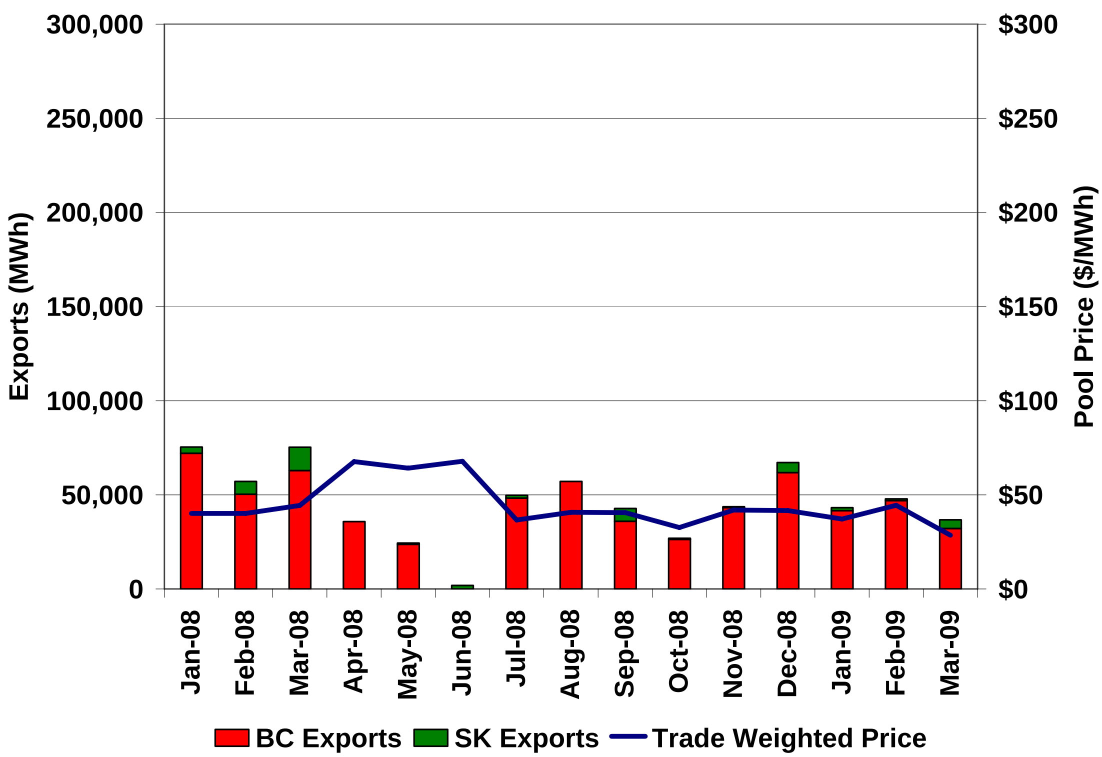


Figure 13 - On-Peak Prices in Other Markets

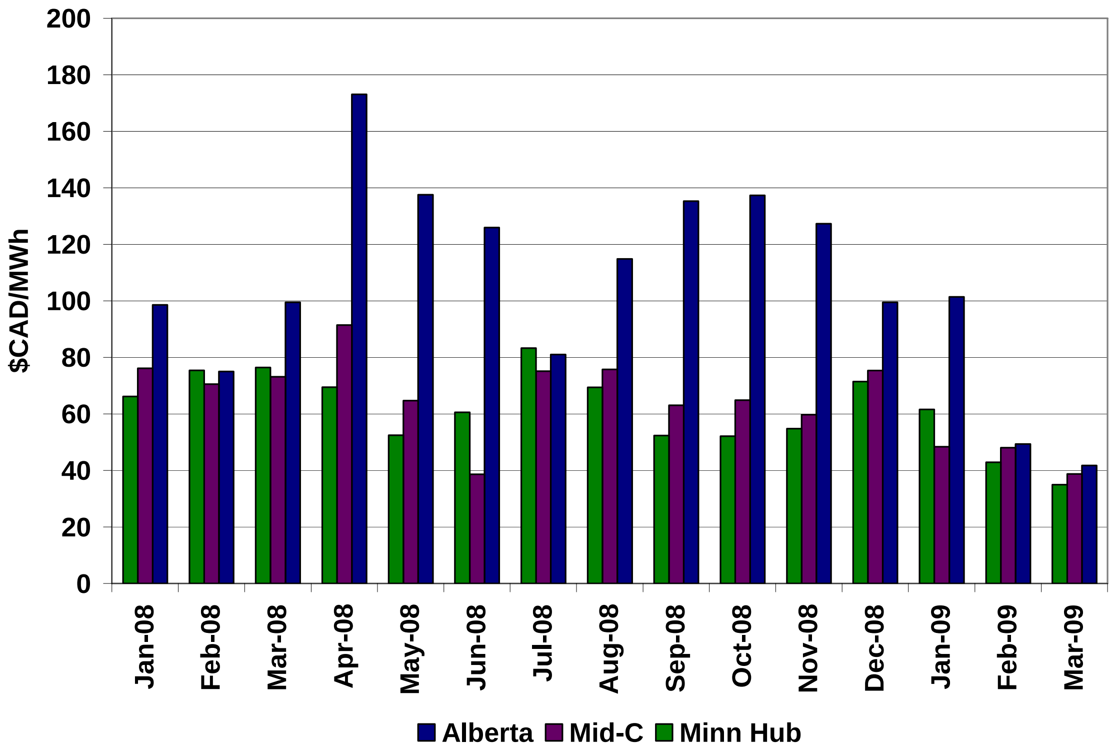
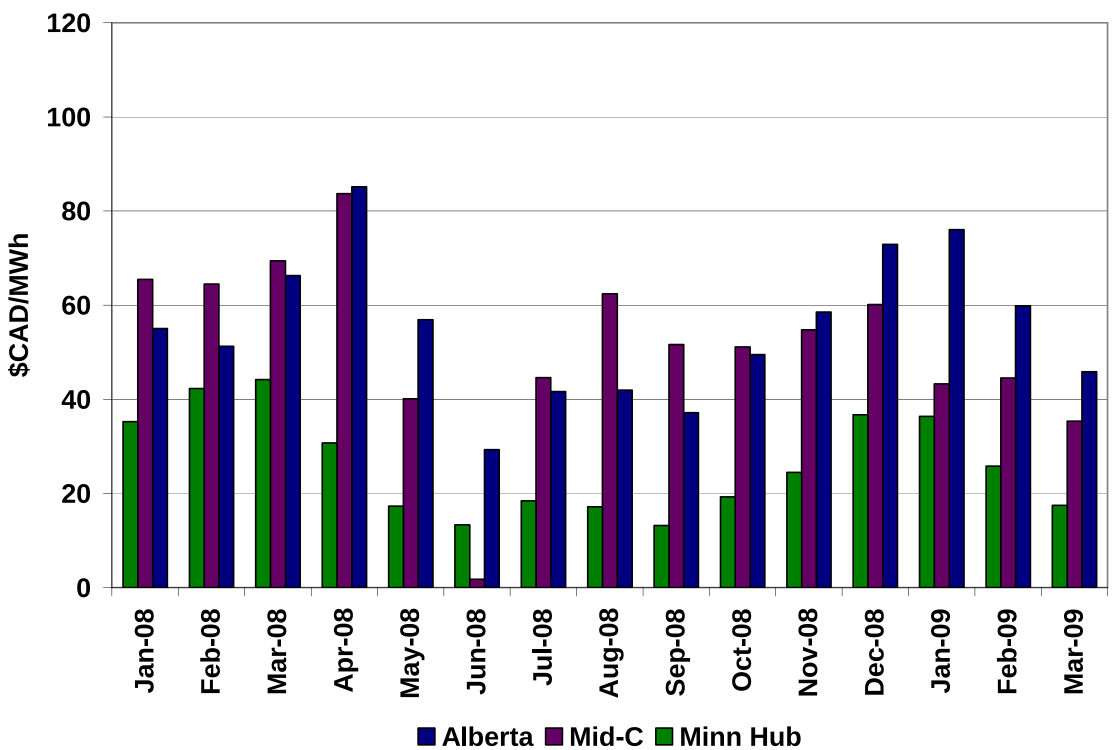


Figure 14 - Off-Peak Prices in Other Markets



APPENDIX C – 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 15 - Active Settlement Prices - All Markets (NGX and OTC)

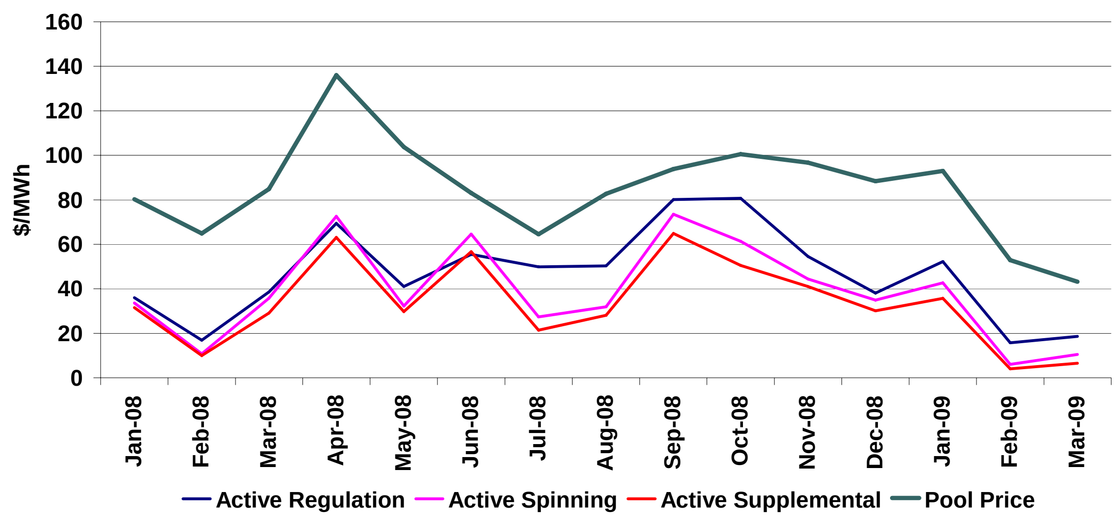


Figure 16 - Standby Premiums - All Markets (NGX and OTC)

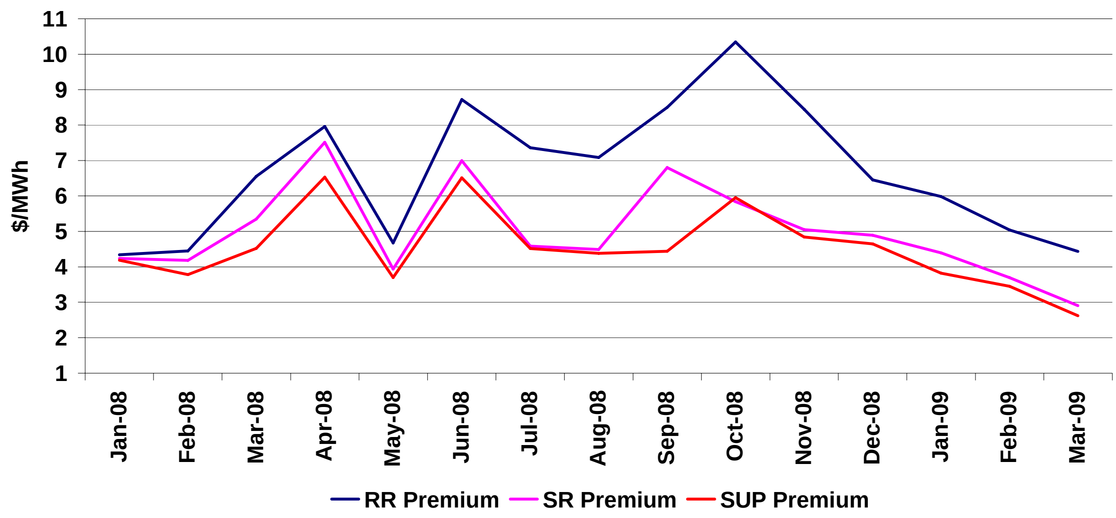


Figure 17 - Activation Prices - All Markets (NGX and OTC)

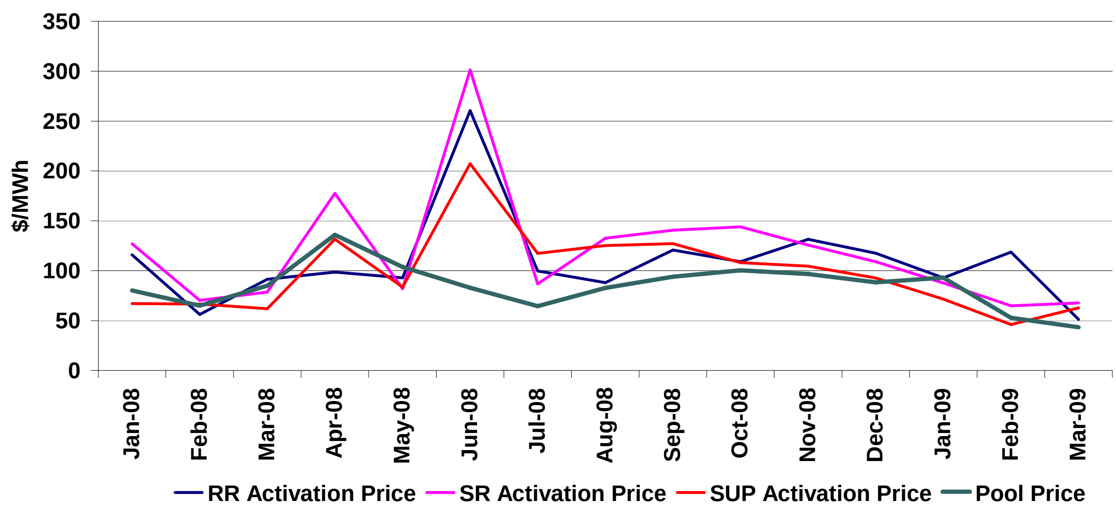


Figure 18 - Standby Activation Rates

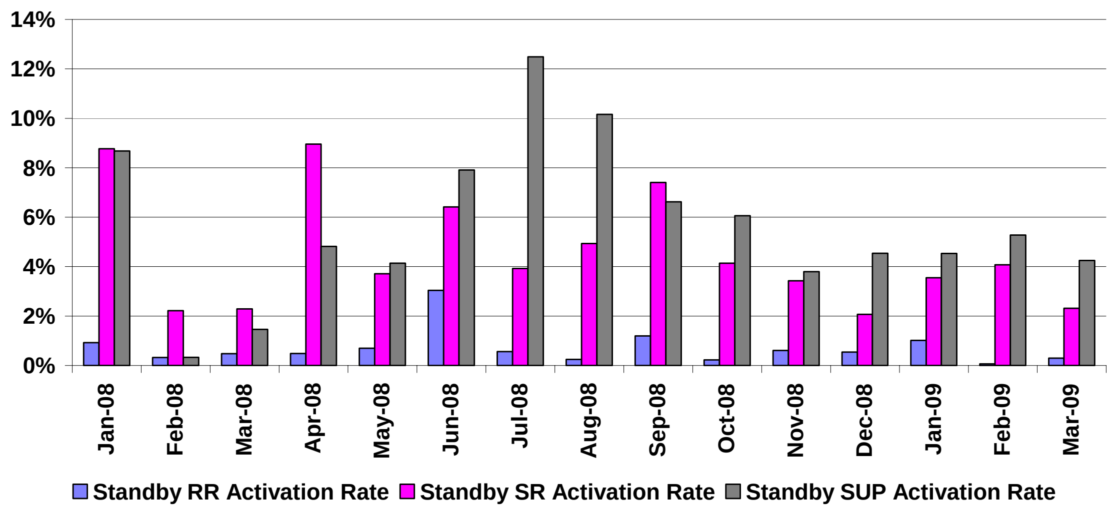


Figure 19 - OTC Procurement as a % of Total Procurement

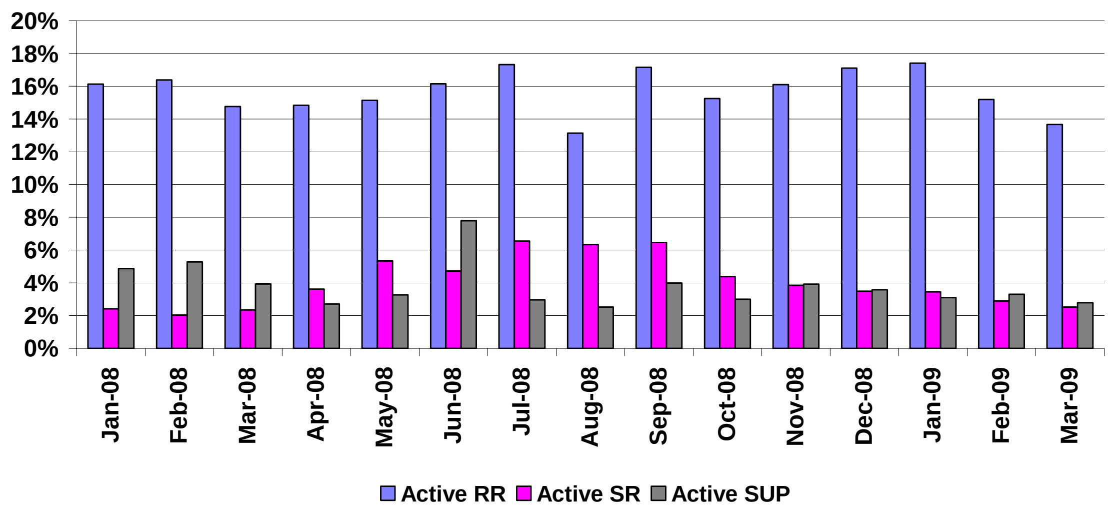


Figure 20 - Active Regulating Reserve Settlement by Market

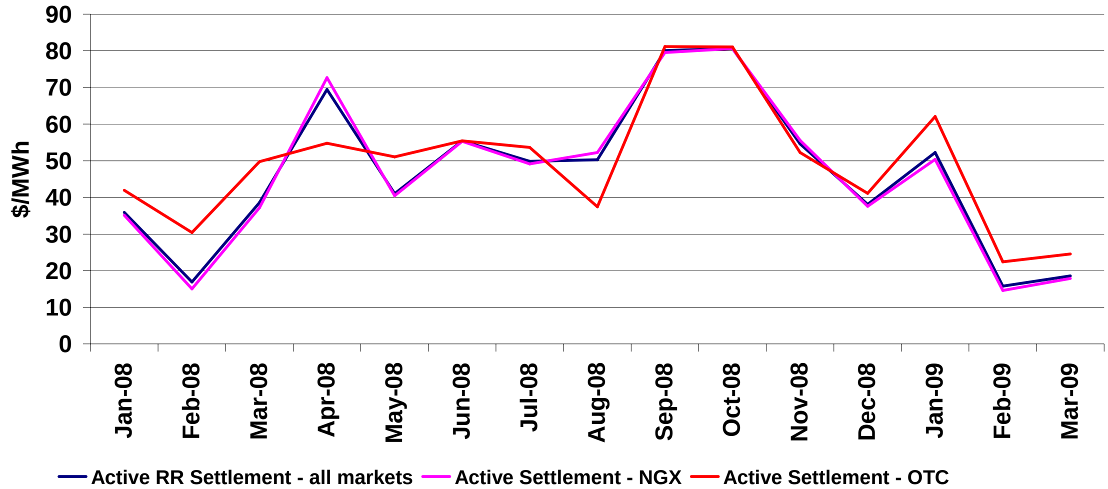


Figure 21 - Active Spinning Reserve Settlement Price by Market

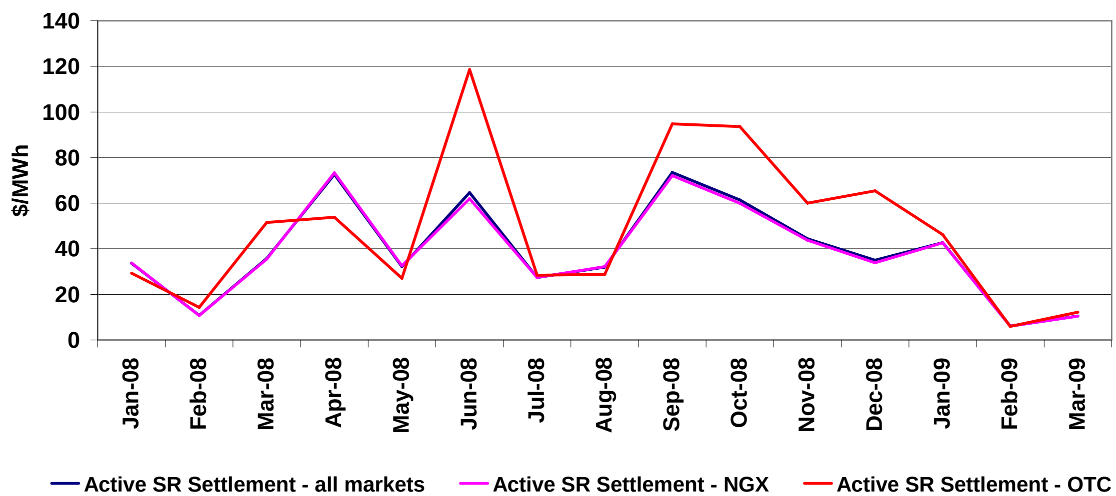


Figure 22 - Active Supplemental Reserve Settlement Price by Market

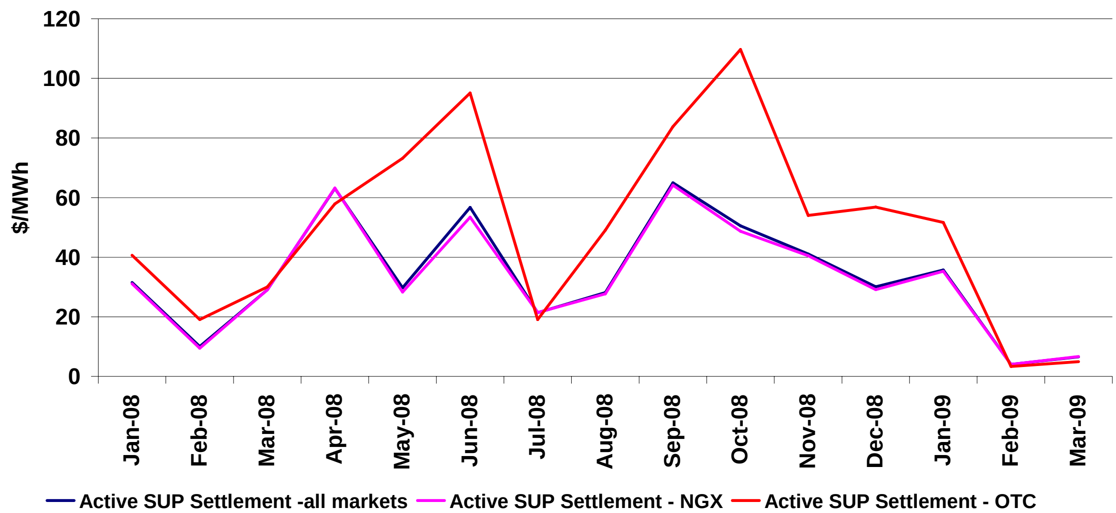


Figure 23 - Active Regulating Reserve Market Share by Fuel Type

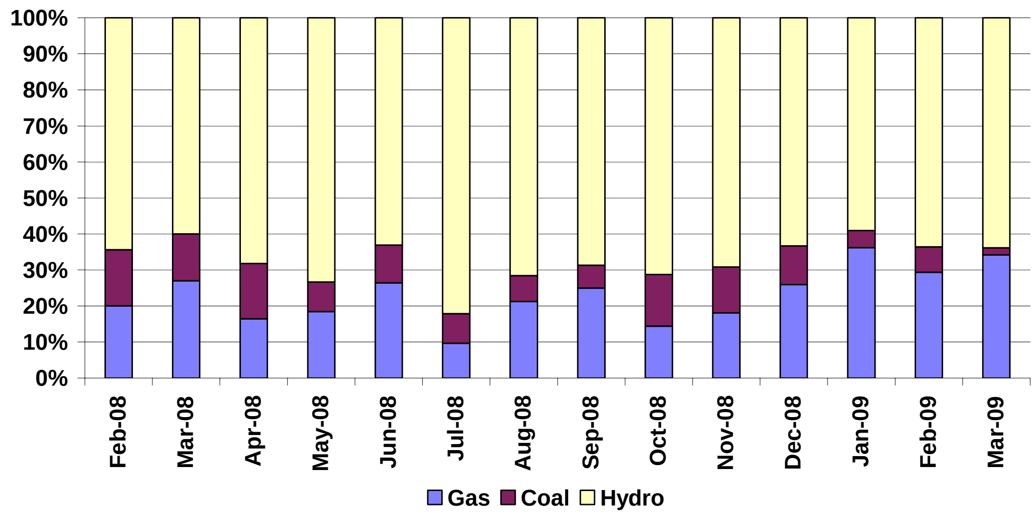


Figure 24 - Active Spinning Reserve Market Share by Fuel Type

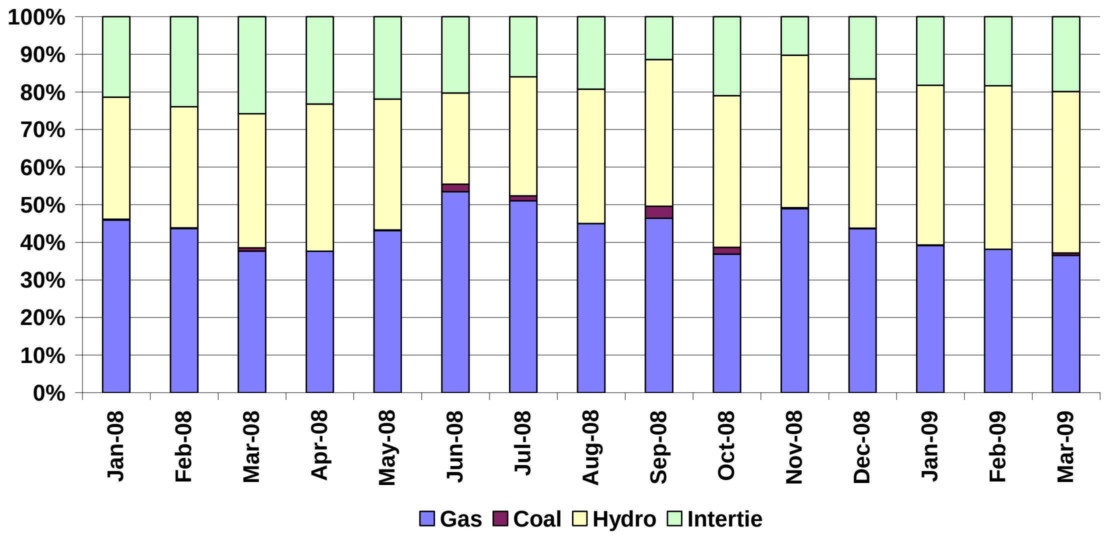
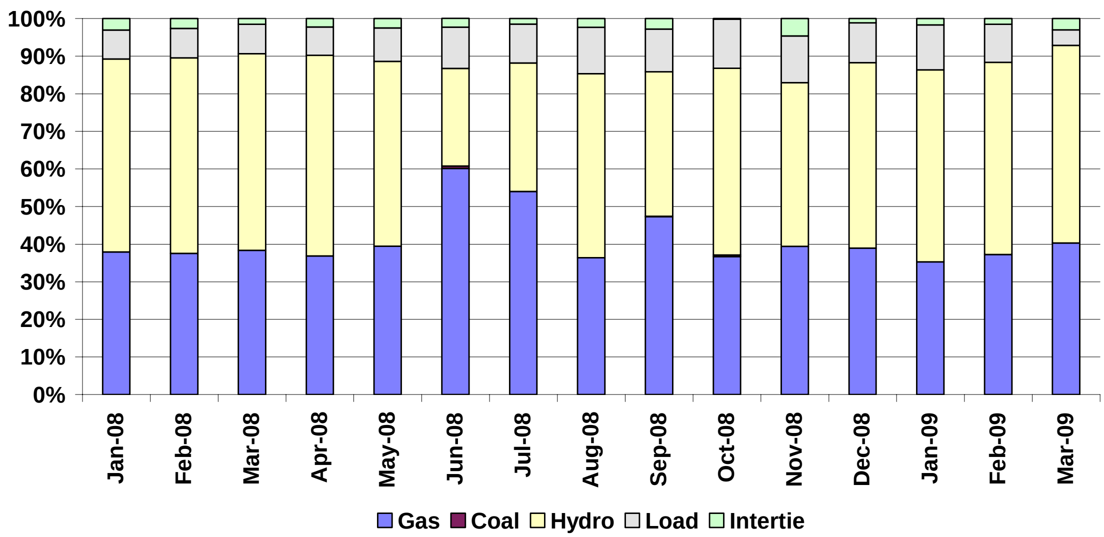


Figure 25 - Active Supplemental Reserve by Fuel Type



APPENDIX D – DDS METRICS

Table 3 - 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]
January	$1.52	65,503	5,162,772	$0.29	$23.21
February	$1.35	56,502	4,596,890	$0.29	$23.90
March	$1.15	68,041	4,952,895	$0.23	$16.93
Total	$4.02	190,046	14,712,557	$0.27	$21.16

Figure 26 - Average Daily TMR. Available, Eligile & Dispatched DDS Volumes (MW)

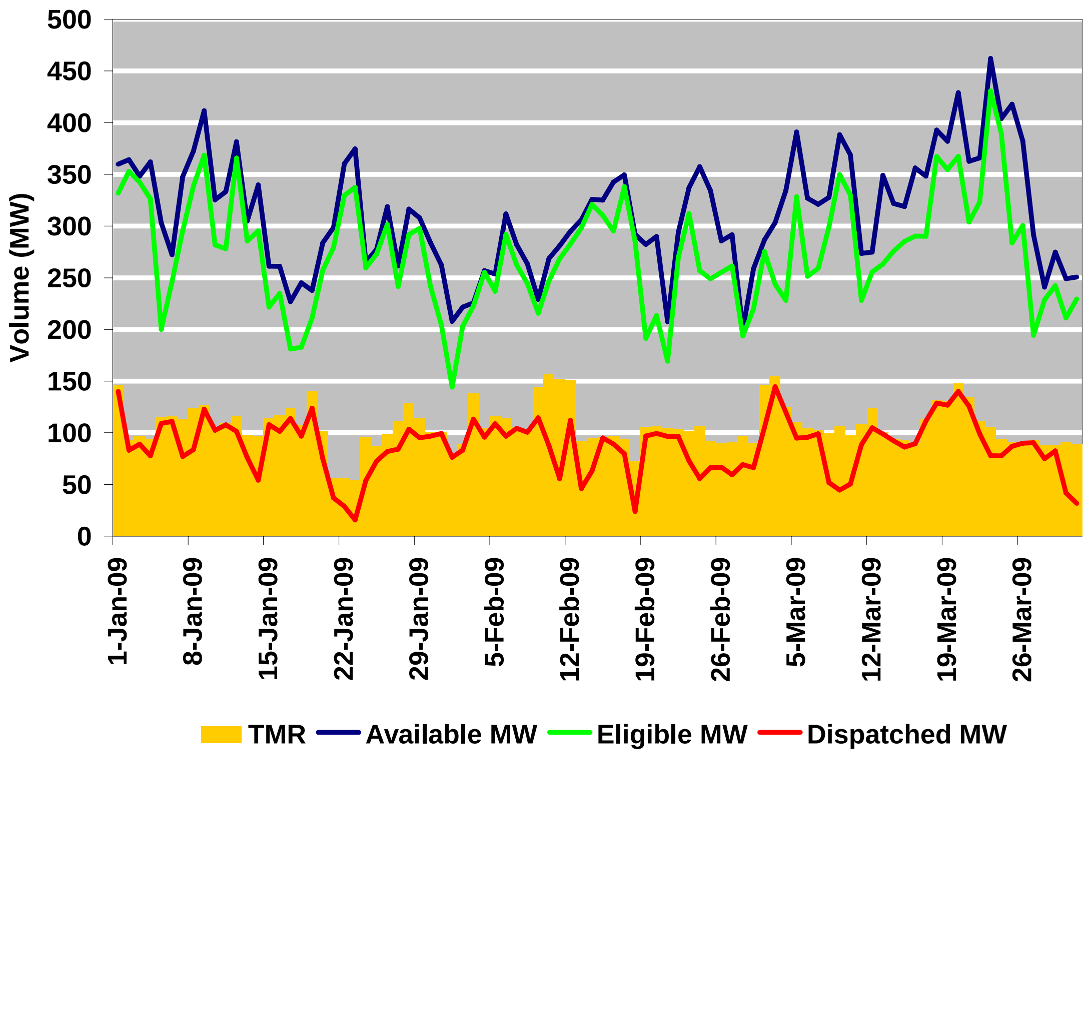


Figure 27 - Average Daily DDS Dispatched and Constrained Down Volume (MW)

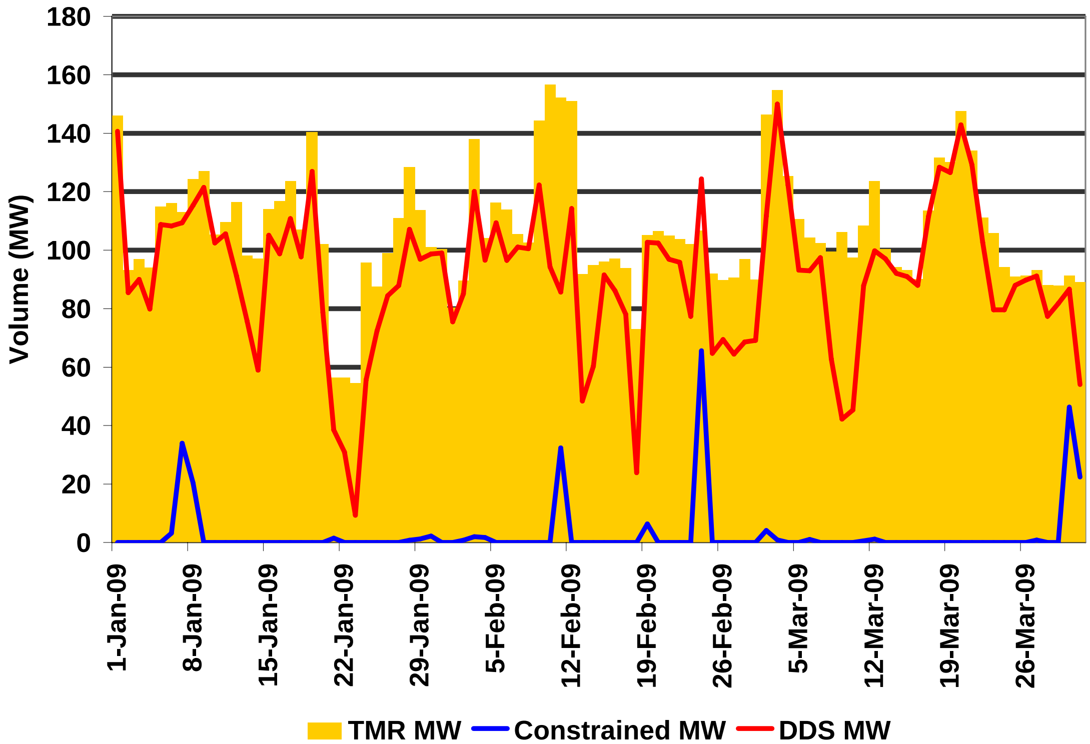


Figure 28 - Average Weekly DDS Market Share by Submitting Participant

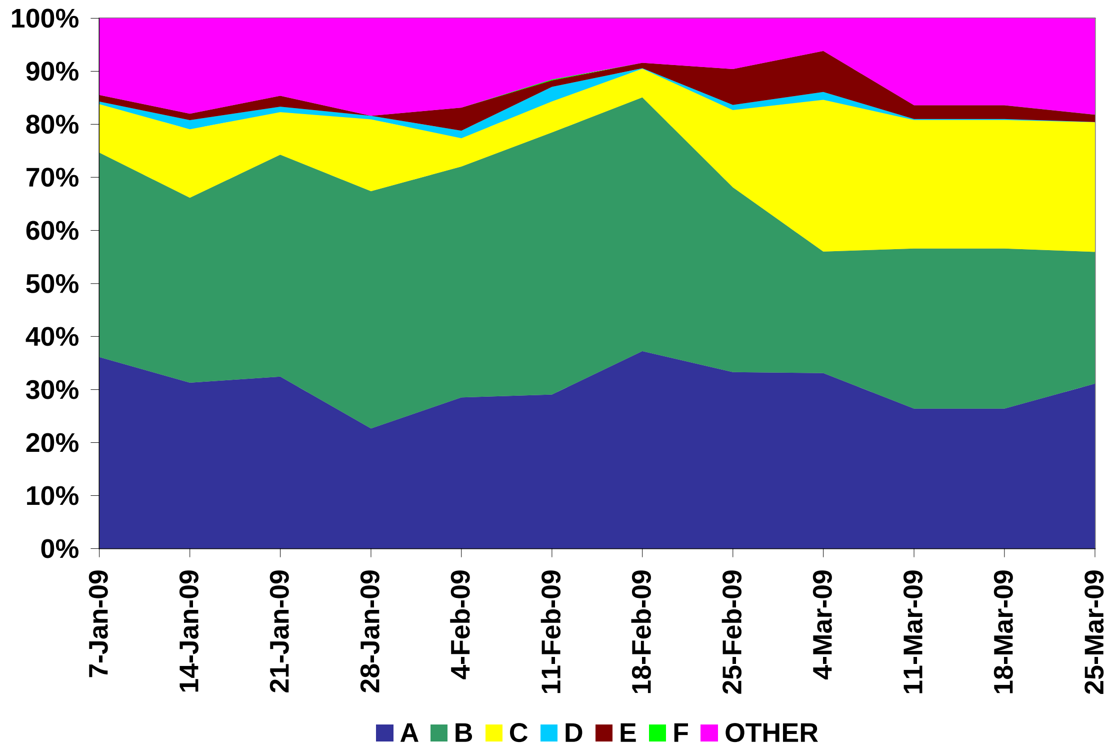
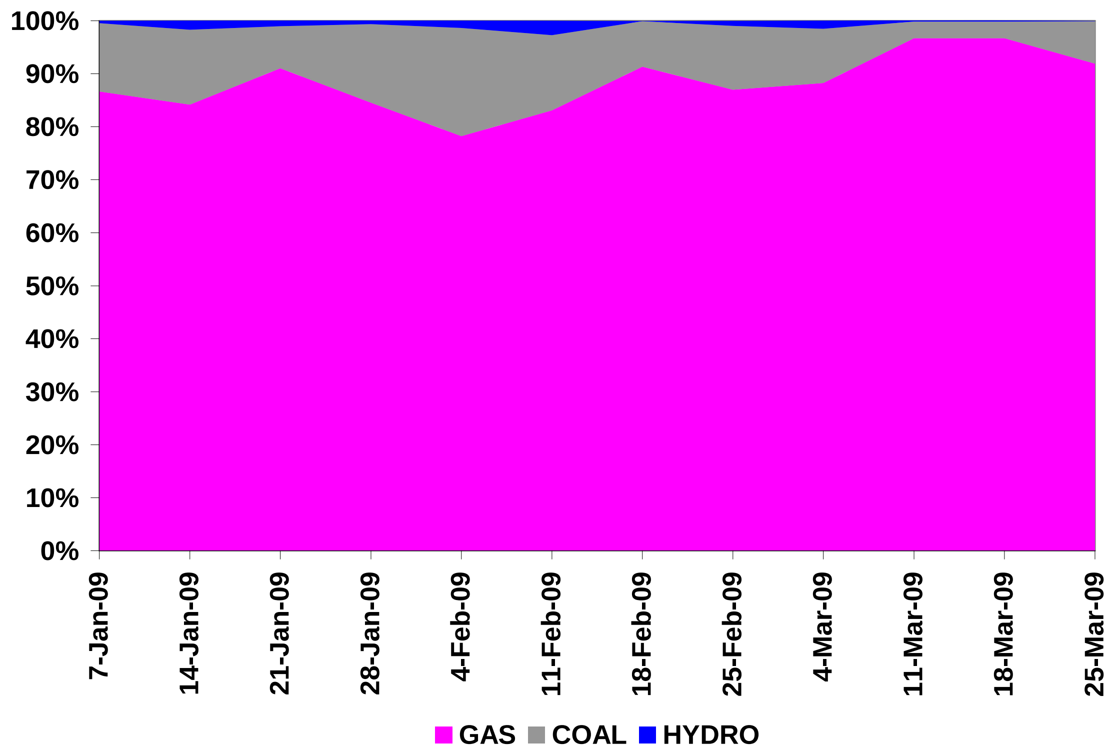


Figure 29 - Average Weekly Market Share by Fuel Type



APPENDIX E – FORWARD MARKET METRICS

Figure 30 - Volume by Trading Month

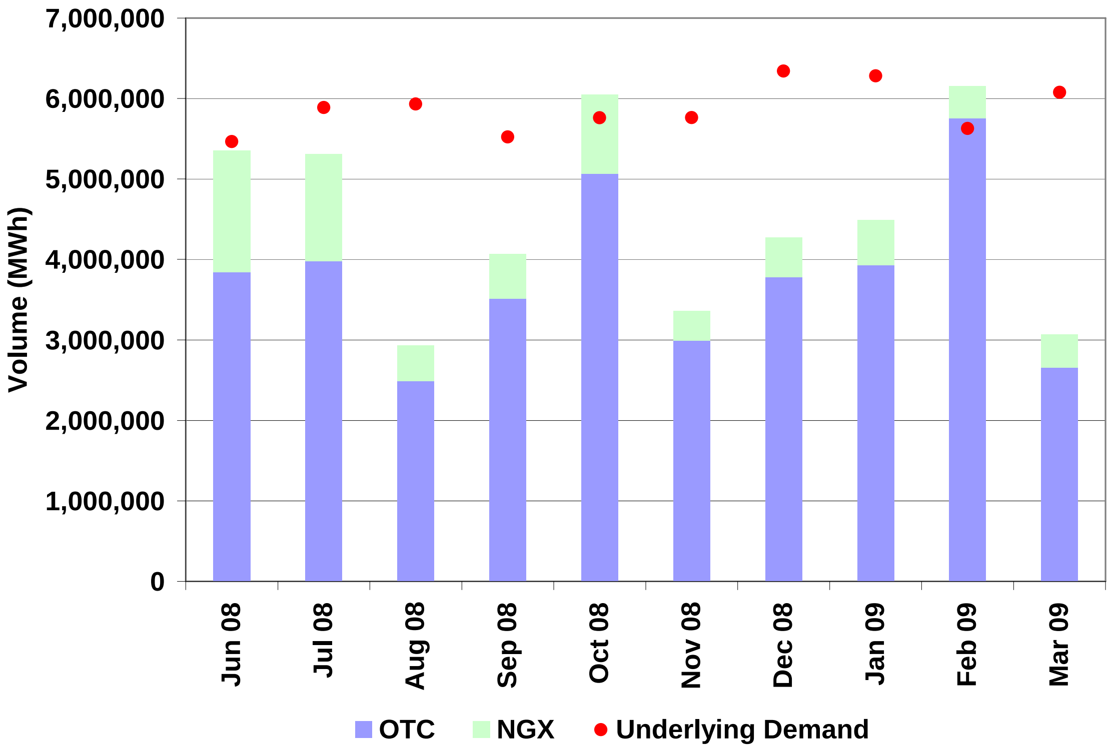


Figure 31 - Number of Participants by Trading Month