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MSA REPORT

Quarterly Report

October - December, 2009

February 10, 2010

MARKET SURVEILLANCE ADMINISTRATOR

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1 WHOLESALE MARKET

1.1 Wholesale Market Fundamentals

Pool Price

Q4/09 electricity prices in Alberta averaged $46.27/MWh (Table 1 in Appendix A). This is 7% lower than Q3/09 ($49.49/MWh) and 51% lower than Q4/08 ($95.16/MWh).

The annual average Pool price in 2009 was $47.81/MWh, a drop of 47% from 2008 ($89.95/MWh).

Natural Gas

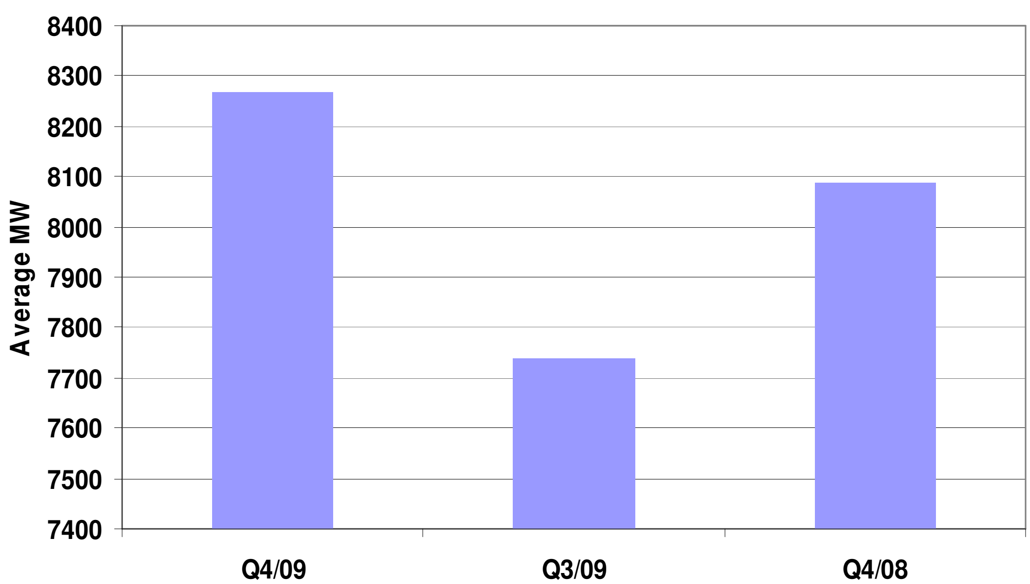
In Q4/09, the average AECO natural gas prices increased 53% over the previous quarter, from $2.82/GJ to $4.31/GJ (Figure 3 in Appendix A). However, the gas price was 32% below the Q4/08 average of $6.35/GJ.

Overall, natural gas prices in 2009 averaged 51% lower than in 2008 ($3.76/GJ vs $7.73/GJ). Lower year-over-year natural gas prices made it possible for gas-fired units to offer more competitively than the previous year. This contributed to the lower year over year annual average Pool price.

Demand

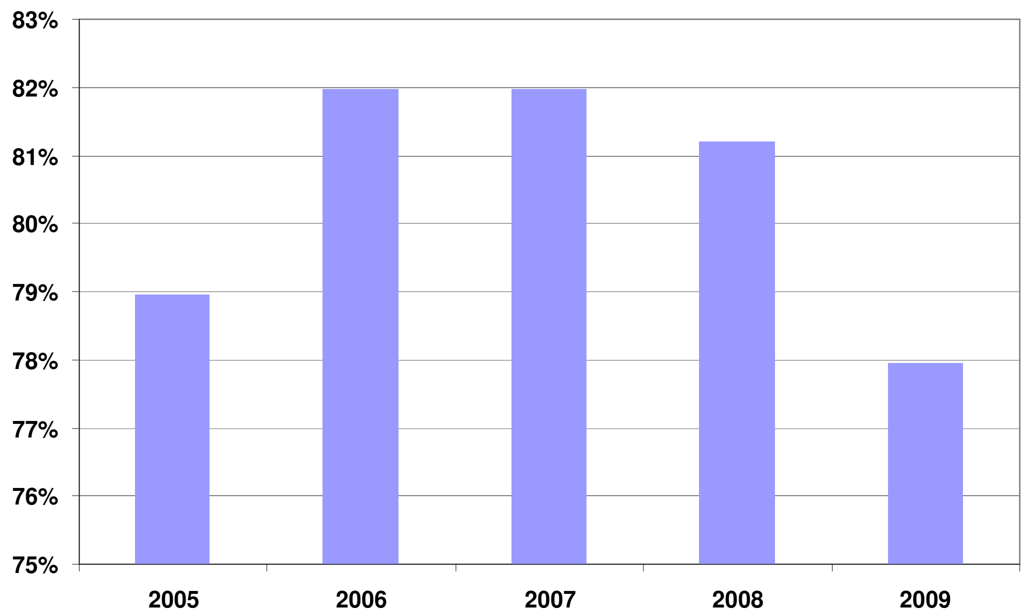
A new record peak demand of 10,236 MW was set on December 14, 2009. The average demand in Q4/09 increased to 8,270 MW from the 7,738 MW in Q3/09 and the 8,086 MW in Q4/08 (Figure i).

Figure i: Quarterly Average Demand



While peak demand in 2009 increased 4.4% from the old record of 9,806 MW, the average demand only increased 0.2% year over year. This resulted in a decline in the system load factor in 2009 of 3%. Load factor is the ratio of the average demand to the peak demand. The 2009 load factor fell to the lowest level in five years (Figure ii). The drop in load factor is likely caused by the reduced share of industrial load relative to commercial and residential loads. Commercial and residential loads tend to be much ‘peakier’ than industrial loads.

Figure ii: Load Factor



Supply

In Q4/09, a total of 298 MW of capacity was added to the province’s generating fleet (Table i).

Table i: New Capacity Additions in Q4/09

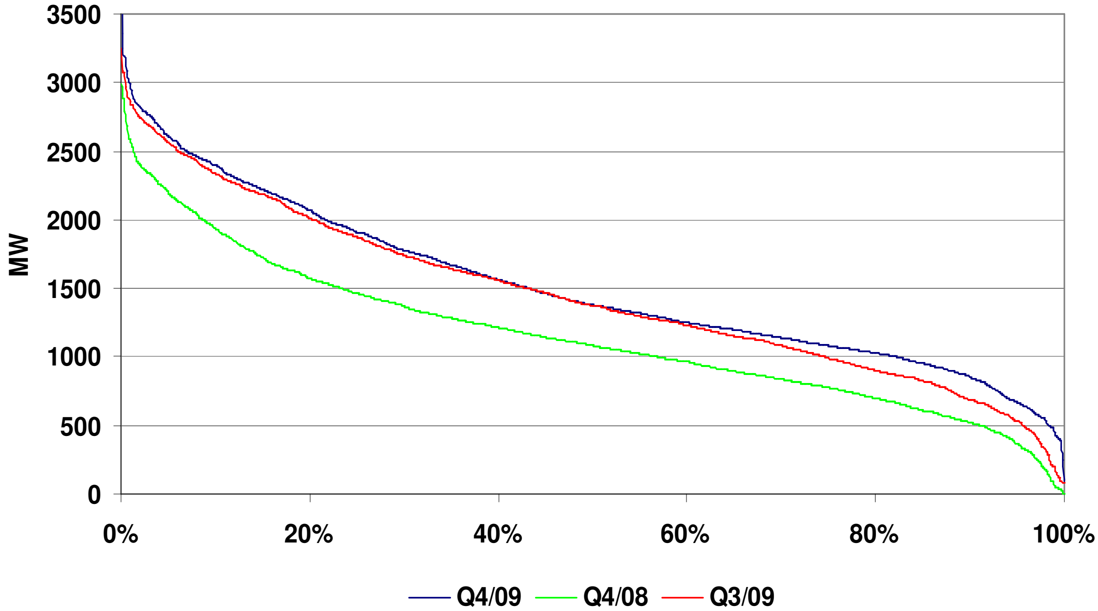
Unit	MW	Fuel Type	Note
Sundance 5	53	Coal	Increased from 353MW to 406MW
Crossfield 1	40	Gas	
Tayor Hydro	2	Hydro	Increased from 12MW to 14MW
Clover Bar 3	101	Gas	
Crossfield 2	40	Gas	
Crossfield 3	40	Gas	
Medicine Hat 1	15	Gas	Increased from 243MW to 258MW
ATCO Scotford Upgrader	7	Gas	Increased from 188MW to 195MW

Over the course of 2009, more than 500 MW were added to the generating capacity. The only retirement in 2009 was the 209 MW Rossdale plant that had not been included in AESO Supply Metric due to its intermittent nature. Effectively the addition in generating capacity exceeded the year-over-year peak demand increase of 430 MW and the year-over-year average demand increase of 18 MW, and helped alleviate the market tightness experienced in the recent years.

Market Tightness

Supply cushions[1] for Q4/09, Q3/09 and Q4/08 are shown in Figure iii. Of the three quarters shown, Q4/08 experienced the most frequent tightness. Even with higher demand, Q4/09 had a greater supply cushion than Q3/09, due to increased generating capacity and availability (Table 2 of Appendix B).

Figure iii: Supply Cushion Duration Curves



The less tight market in Q4/09 dampened the pool prices (Table 1 in Appendix A) and market heat rates (Figure 6 in Appendix A). In contrast to the pool price duration curves where Q4/09 is entirely below that of Q4/08 (Figure 1 in Appendix A), the heat rate duration curves of Q4/09 and Q4/08 overlap about 90% of the hours (Figure 6 in Appendix A). In the remaining 10% of the hours, the Q4/09 heat rate duration curve was noticeably lower than that of Q4/08. This is because greater supply cushion in Q4/09 reduced the occurrence of price spikes.

Price spikes mostly occur when supply cushion is low (thin) as shown in Figure iv and Figure v. These two figures plotted the supply cushion duration curves and the corresponding hourly pool prices.[2] In 2009, less than 3% of the time was the supply cushion below 500 MW, whereas in

[1] Supply cushion in this report is measured by the MWs that are part of the energy merit order but not dispatched. It doesn't include the MWs that are offline or dispatched into the Operating Reserves market.

[2] Since data are only available from January 12, 2008, these hourly data only compare the hours between January 12 and December 31.

2008, the same parameter was 12%. Less frequent occurrence of thin supply cushion reduced the number of price spikes in 2009.

Figure iv: Pool Prices and Supply Cushion Duration Curve - 2009

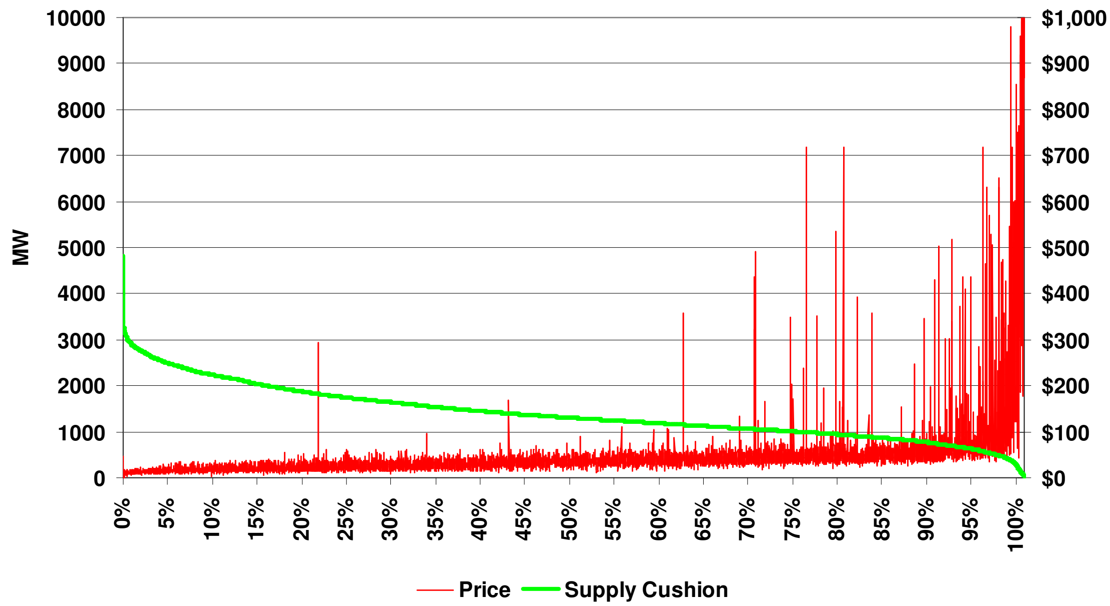
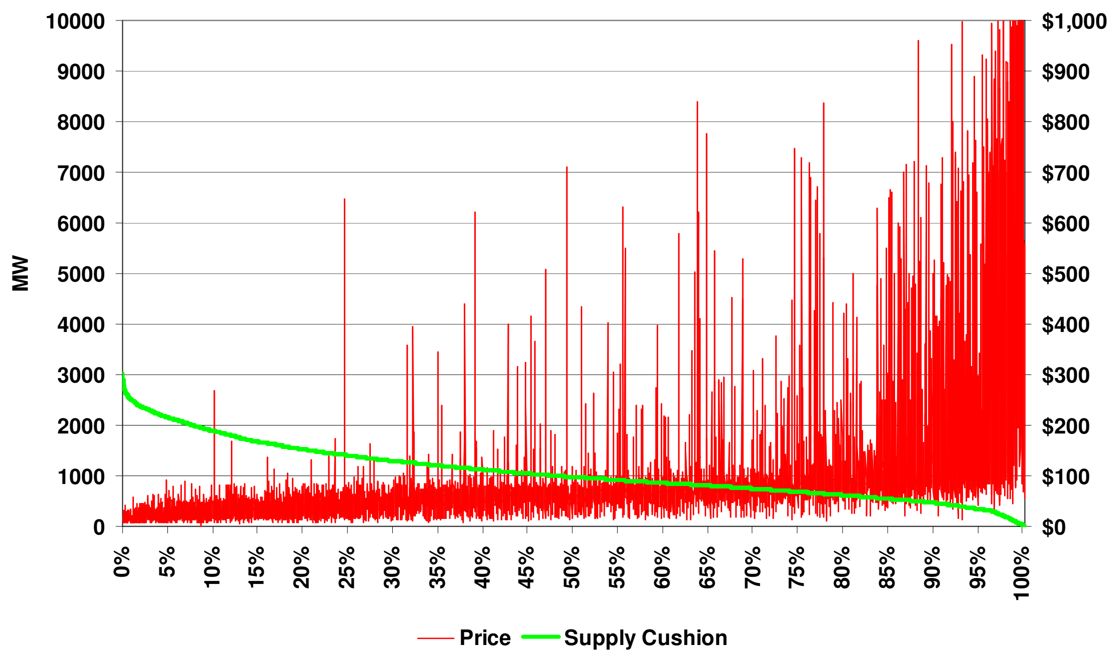


Figure v: Pool Prices and Supply Cushion Duration Curve - 2008



1.2 SVC Outage and BC Intertie ATC

Through October, November, and the first few days of December, the Langdon Static VAR Compensator (SVC) was offline for replacement, which impacted the import and export Available Transfer Capacity (ATC) across the AB-BC interconnection.

OPP 304 Alberta-BC Interconnection Transfer Limits describes the Import and Export Total Transfer Capability (TTC) for the AB-BC interconnection under normal system conditions and under other system conditions, such as the SVC being out of service.

Specifically, it describes that when the SVC is out of service, import TTC is set at 465 MW, which under typical system conditions results in a 400 MW Import ATC.[3] OPP 304 also describes how Export TTC varies with Alberta Internal Load (AIL) in the summer and winter season. Table ii summarizes the Export TTC and typical Export ATC when the SVC was out of service.

Table ii: BC Export ATC with SVC Out of Service

SVC Out of Service (Winter)	Export TTC (MW)	Typical Export ATC (MW)		Import TTC (MW)	Typical Import ATC (MW)
AIL ≥ 9000 MW	65	0		465	400
AIL < 9000 MW	465	400		465	400

Early in December the SVC returned to service, and was no longer the primary limiting factor in AB-BC interconnection transfer limits. Under normal operating conditions, BC Export TTC is a function of South of KEG 240 (SOK 240) transfer limits, forecasted SOK generation, and forecasted SOK load.[4] Import TTC is defined in OPP 304 for various AIL levels, but through most of December was constrained by OPP 312 – Import Load Remedial Action Scheme (ILRAS) and Load Shed Service (LSS). OPP 312 specifies Import TTC under various levels of LSS and ILRAS, and various level of AIL.

After the SVC returned from outage in early December, BC Import ATC has been generally higher but more variable than observed in October and November. The BC Export ATC has also been more volatile, with SOK-240 Transfer capacity often the limiting factor.

1.3 Operating Reserves

There were two items of particular interest observed in the Operating Reserves Market in Q4/09.

Volatile On-Peak Active Regulating Reserve Trade Index

Since July 2009, the MSA has observed large volatility in the on-peak active regulating reserve trade index. Trade index is the volume weighted

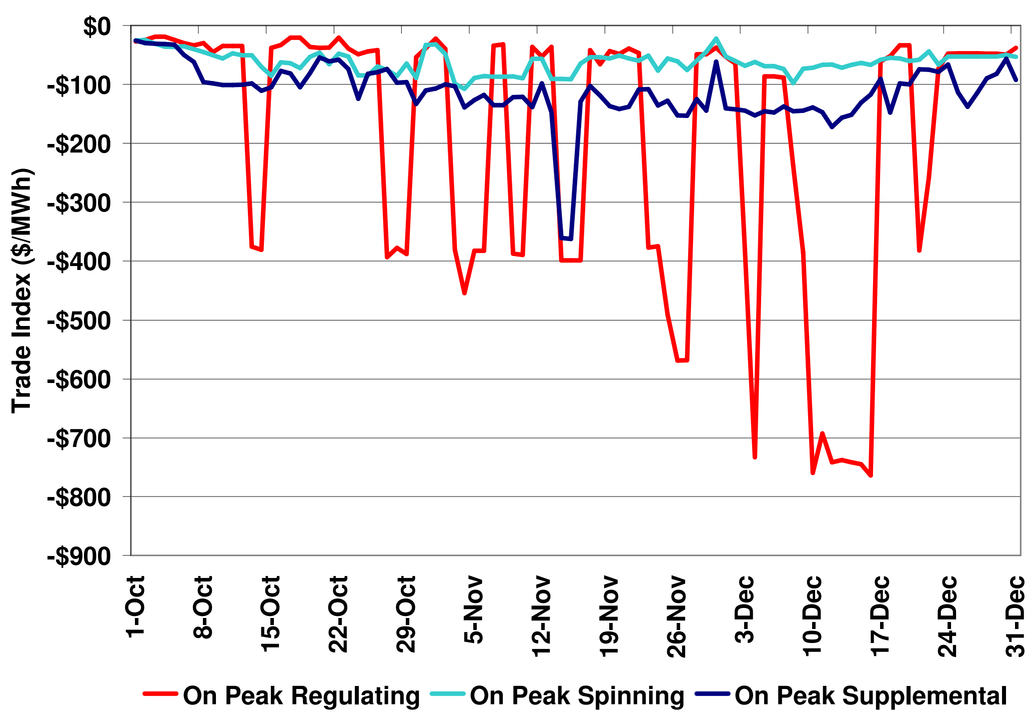
[3] Note that [Available Transfer Capacity] = [Total Transfer Capacity – Transmission Reserve Margin], where the Transmission Reserve Margin is equal to 65 MW under normal system conditions. See OPP 304 Table 1 for details.

[4] SOK 240 transfer limits are defined in OPP 521, as are definitions for SOK load, and SOK generation.

average of trade prices of different trading days. The operating reserves products are traded throughout the five business days before dispatch. Since AESO procures the majority of the volumes on the last trading day before dispatch, the trade indices are largely determined by the trade price of that trading day.

Some market participants offer active on-peak regulating reserve at deep discounts. They do not necessarily intend to set market clearing price, but rather act as price takers in order to sell volumes. When the market is not cleared by any of these participants but by one who offers at higher prices, the trade price of active on-peak regulating reserve is more in line with those of other active on-peak products. When the market happens to be cleared by a participant that offers deep discounts, the trade price is significantly lower. Since the supply curve of on-peak active regulating reserve is typically very steep on the last trading day, slight changes in offer volumes or demand may lead to large spikes or dips in the trade price on the last trading day, and in turn cause high volatility in the trade index (Figure vi).

Figure vi: Q4/09 Trade Indices for On Peak Operating Reserves



Since Q3/09, there has been an increase in the number of market participants who offered large discounts in the on peak active regulating reserve market. Some sellers have been competing for greater market share by offering at discounts that are bigger than the Pool price cap (i.e. offering at a discount to Pool price that is greater than $1000). Having greater volume offered at deep discounts has led to more frequent dips and dips of greater magnitude in on-peak active regulating reserve trade indices in Q4/09.

Since the paid price from AESO to the sellers is based on Pool price less the discount and if the paid price is negative, it is set to zero, in any hour when the Pool price is smaller than the discount, the sellers receive no payments for providing regulating reserve. Offering discounts that are larger than the Pool price cap increased the occurrences of providing active on-peak regulating reserve for free in Q4/09. Although the average Pool price in Q4/09 dropped 7% quarter over quarter, the paid price for active on-peak regulating reserve dropped 53% from the previous quarter in Q4/09.

However, the ability of offering substantial discount to Pool price is limited for participants whose opportunity costs of providing the product are higher than zero. As of writing, the price index for active on peak regulating reserve has not had any significant dips in 2010. A decrease in the number of market participants offered at discounts that are larger than the Pool price cap has been observed.

High Activation Rate of Standby Supplemental Reserve in October

In October 2009, there is a noticeable surge in the activation rate of standby supplemental reserve (Figure 13 in Appendix C). This is because the amount of required active supplemental reserve was underestimated for a part of the month. The volume of contingency reserves (spinning and supplemental reserve) required to protect the system depends on the amount of internal generation (load plus exports) and differences between the forecast and actual can cause more standby to be activated. Standby reserves are procured by AESO to cover any outages by active reserve providers and any forecast errors such as described here.

2 PUBLICATION OF MERIT ORDER DATA

Under Section 6 of the Fair, Efficient and Open Competition (FEOC) Regulation,[5] the AESO is required to “make available to the public the price, quantity and asset identification associated with each offer made to the power pool that is available for dispatch” 60 days after the offers are made. On October 31, 2009, the AESO started to publish merit order reports. The reports consist of snapshots of the System Controller’s Dispatch Tool taken at the mid-point of the hour and include energy merit order, operating reserves merit order and dispatch down service (DDS) merit order. Respectively they are identified as Merit Order Snapshot – Energy, Merit Order snapshot – Ancillary Service and Merit Order Snapshot – DDS reports in the AESO Energy Trading System (ETS). The

[5] http://www.auc.ab.ca/acts-regulations-and-auc-rules/acts-and-regulations/Documents/AUC/AR159-2009.pdf

description of merit order reports can be found in AESO Information Document (ID) issued on August 31, 2009.[6]

2.1 Portfolio Offer Behavior

In past quarterly reports the MSA has commented on the effects of portfolio offer behaviour on market outcomes. Here, we explore some examples of portfolio offer behaviour observed in Q4/09, this time with the benefit of the data from Merit Order snapshots to illustrate some of the details previously unavailable to the public. The purpose in doing so is to fulfill the MSA oversight responsibilities to understand and communicate the cause of Pool price movements. This section is also meant to initiate a dialogue on the appropriate response of the MSA when incidents of this nature are observed in Alberta's 'energy only' market.

Portfolio offer behavior is characterized as a market participant optimizing the value of its portfolio of assets, which may include generation assets, load, and forward buy/sell obligations. The premise of portfolio offer behavior is that the coordination and optimization of all assets within the portfolio will yield greater returns than the sum of individual portfolio asset optimizations.

The following examples illustrate some portfolio offer behavior that occurred in Q4/09. There are no Pool rules or MSA guidelines that prohibit or restrict the portfolio offer behavior that these examples illustrate. However, the MSA believes that by demonstrating these examples of actual events, the market can gain some insight into the MSA's view of what can explain some price excursion in the market.

Change in Offer Behavior in Response to Change in Portfolio Length

This example is one where offers from an asset were significantly changed seemingly in response to the loss of 'length' of a portfolio to which the asset belongs.

UNIT 1 and UNIT 2 both belong to the same portfolio (denoted as Portfolio A). On Friday November 6th, 2009, UNIT 2 went offline for weekend maintenance beginning in HE16, which removed 385 MW of in-merit energy from the market. As a result, the 'length' of Portfolio A was reduced, all else equal. In conjunction with this loss of Portfolio A's 'length', UNIT 1 drastically lowered its offer prices.

Figure vii presents supply curves for UNIT 1 that more clearly illustrate the change in offer block pricing between HE15 and HE16. Note that in HE15, UNIT 1 was offering 223 MW in the energy merit order, and 54 MW was dispatched into the DDS merit order. Similarly in HE16, 226 MW were offered to energy, and 54 MW of dispatched DDS. Figure vii supply curves plot only the energy market offers (i.e. with DDS excluded).

[6] http://www.aeso.ca/downloads/FEOC_ID_v2_-_August_31_Changes_-_Final_Clean.doc

The effect of the re-pricing was a flattening of UNIT 1's supply curve, and resulted in the offered energy being fully dispatched by the end of HE16. While Figure vii presents the offer price in $/MWh, on a heat rate basis,[7] the right-hand side of the supply curve shifted from about a 36 GJ/MWh heat rate down to a 14 GJ/MWh heat rate, significantly closer to the estimated physical heat rate of the asset.

Figure vii: UNIT 1 Supply Curves - November 6, 2009 HE15 and HE16

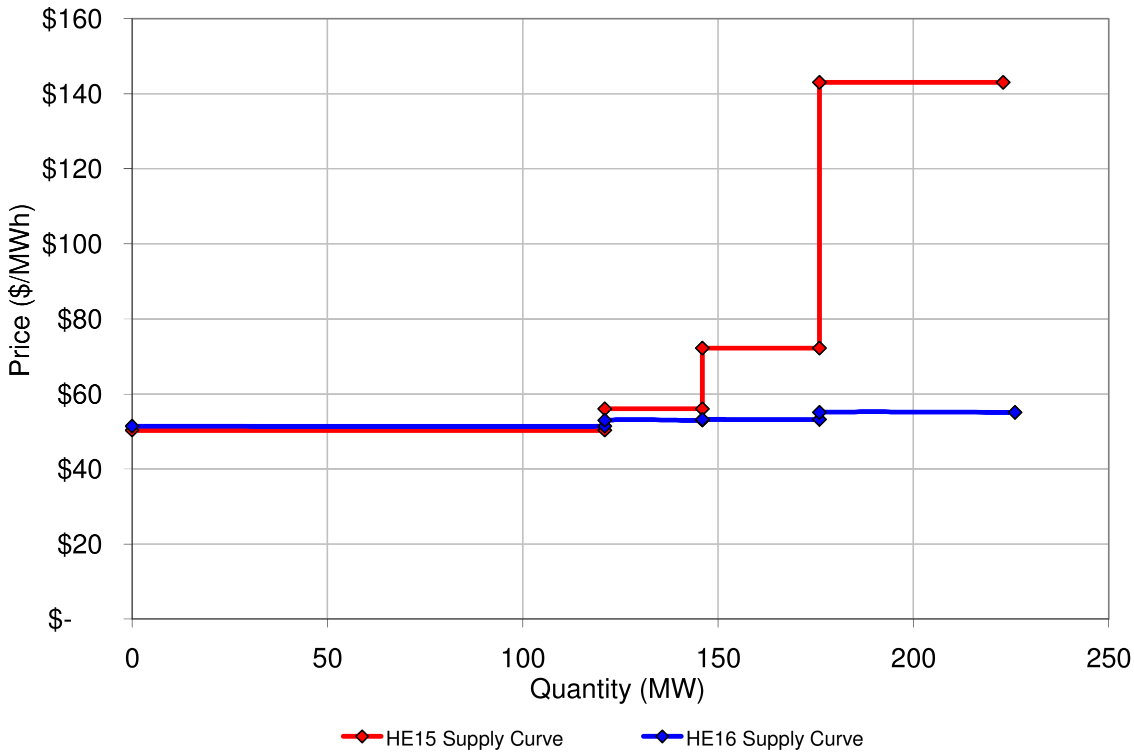


Figure viii illustrates the interplay between generation levels of UNIT 1 and UNIT 2, after the loss of UNIT 2 and the re-pricing into merit of UNIT 1.

The re-pricing of UNIT 1 offer blocks to coincide with the planned outage of UNIT 2, replaced some, but not all, of the in-merit energy production lost to the UNIT 2 outage.

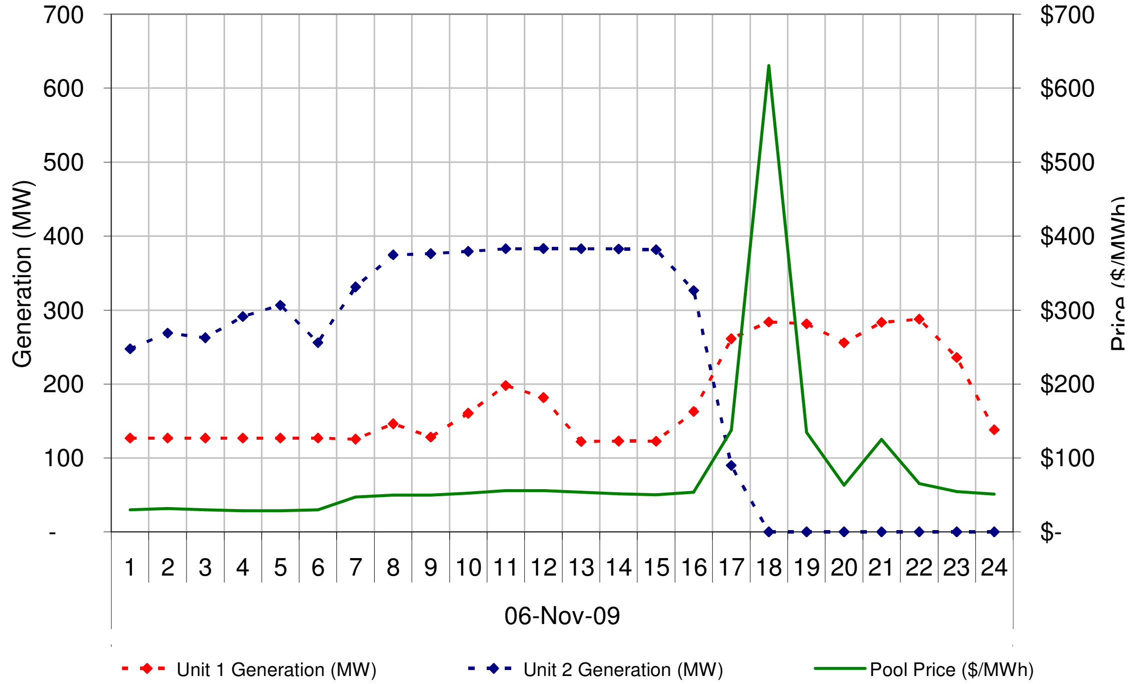
The chart also illustrates that pool price rose dramatically between HE16 and HE18. This price spike was the result of not only the loss of UNIT 2, but also a tighter overall supply situation during daily peak demand, as coal availability dropped to 68% in those hours.

This example illustrates portfolio offer behavior where an individual asset is re-priced at the same time as a change of the portfolio 'length' it belongs to. This particular example is one where the portfolio offer behavior did not

[7] Based on the NGX AB-NIT index gas price that day

appear to have an effect on market price, as any potential pricing effect of offer behavior was overtaken by other events in the market. However, absent these other events, and all else being equal, this portfolio offer behavior would have resulted in a lower market price, than if UNIT 1 had not been offered into merit in HE16.

Figure viii: UNIT 1 and UNIT 2 Generation Summary



Pricing up When Market Becomes Tighter

This example describes changes in offers for a 'long' portfolio seemingly in response to a possible tight market. We assume the participant is 'long' since the pricing behaviour was consistent with such an assumption as is described below.

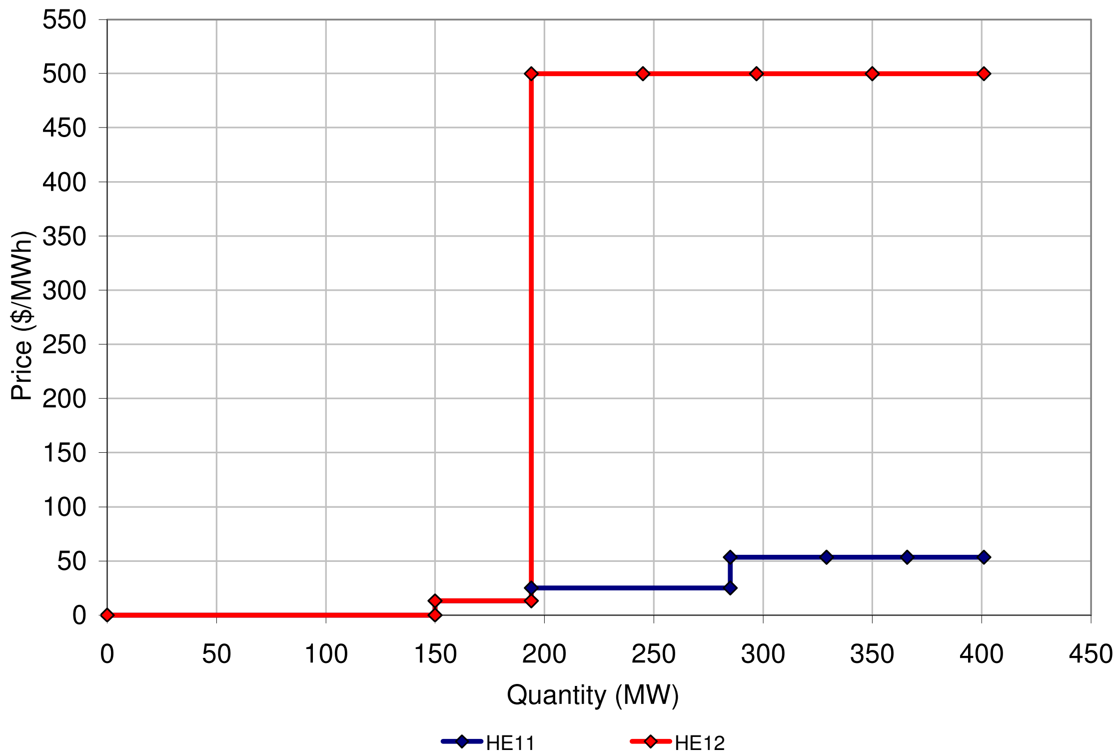
UNIT 1 and a portion of UNIT 2 both belong to the same portfolio (denoted as Portfolio B). On November 23rd, early in HE09, Unit 3 (which is not in Portfolio B) tripped offline, removing 381 MW from the merit order. Shortly thereafter, two units in Portfolio B increased their energy offers for HE12 and HE13. UNIT 1 re-priced 207 MW from the $25-$55/MWh range into the $499-$500/MWh range and UNIT 2 increased the offer price of 50 MW from $22.01/MWh to $499.78/MWh. For simplicity of illustration, the remainder of this example will focus on the offer behavior of UNIT 1.

Figure ix presents the offer supply curves for UNIT 1 in HE11 and HE12, before and after the price restatement.

As the market moved into HE12, there was a significant ramp to manage as 207 MW of UNIT 1 was now out of merit. In dispatching up the merit order to replace the energy and manage the ramp, the System Controller

(SC) required a dispatch as high as 100 MW into the re-priced UNIT 1 offers. This resulted in UNIT 1 setting SMP at ~$499/MWh for a total of 14 minutes in that hour. As other energy came online in the merit order under the UNIT 1 blocks, SMP receded and UNIT 1 was out of merit for the remainder of the hour. Pool price for the hour was $202.20/MWh.

Figure ix: UNIT 1 Supply Curves - November 23, 2009 HE11 and HE12

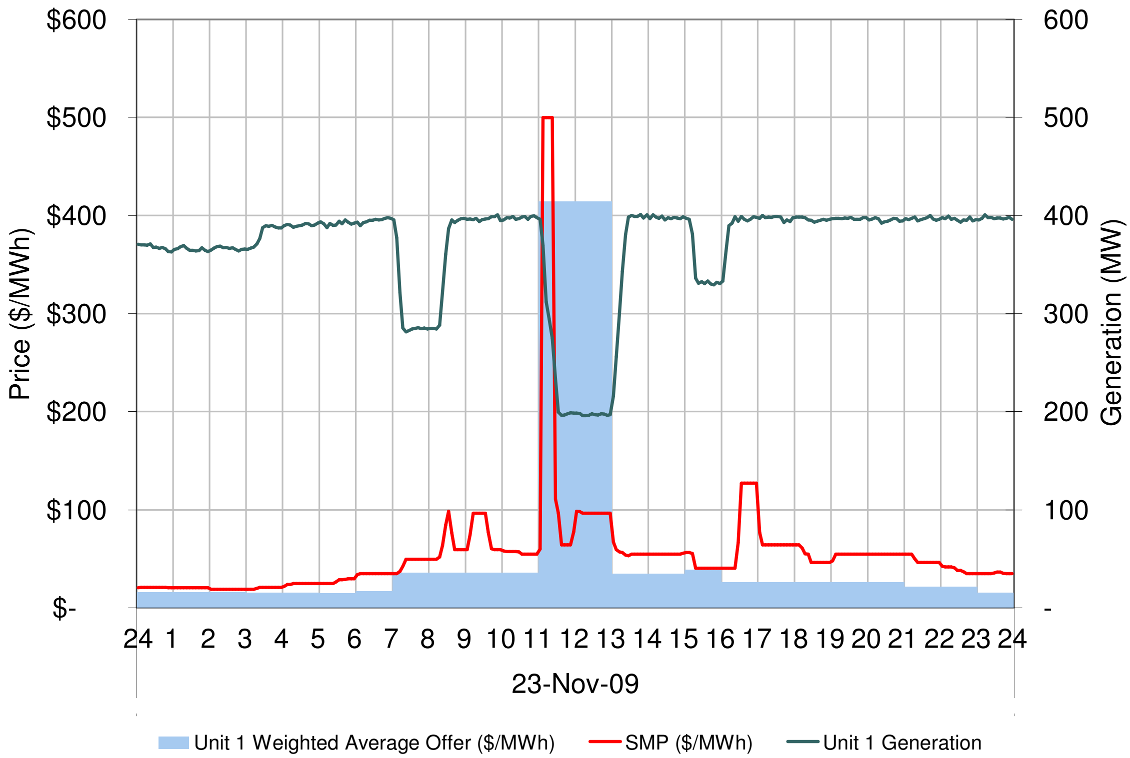


The 207 MW of UNIT 1 priced ~$499/MWh remained out of merit through the bottom half of HE12 and all of HE13, until the offers were re-stated back down to between $32-$44/MWh in HE14, which put the energy back in merit.

Figure x illustrates the UNIT 1 weighted average offer, together with the SMP and UNIT 1 generation. The weighted average offer[8] is a metric that can identify changes in the unit or portfolio's offer behavior. Figure x shows the significant increase in the weighted average offer of UNIT 1 in HE12, and HE13, the corresponding changes in the unit's generation profile, and the effect of the re-pricing on SMP.

[8] The weighted average offer does not include 0$ offer blocks as these are often inflexible blocks, and are not typically representative of a participant's offer strategy.

Figure x: UNIT 1 Energy Offers and Generation



This portfolio offer behavior appears to have been taking advantage of the market tightness caused by the sudden UNIT 3 outage. The MSA observed similar pricing behavior in selected hours later the same week, but the results were less significant in terms of the effect on Pool price.

In this example, the re-pricing strategy likely increased the revenue of Portfolio B as it significantly increased the Pool price of the hour. Although UNIT 1 was out of merit part of the hour, the increased revenue received by other generating MWs in Portfolio B would likely more than offset the revenue ‘sacrificed’ at UNIT 1.

Impacts of Portfolio Offer Behavior

Engaging in portfolio offer strategies is based on the belief that a participant’s choice of offers has some influence on Pool price. Although certain individual assets ‘lose’ on the portfolio offer strategy, as long as the strategy is able to influence the Pool price, the broader portfolio can gain if (i) the size of the portfolio is sufficiently large, and/or (ii) the change in market price, resulting from the strategy, is sufficiently large. A key feature of pricing-up strategy is that gains are realized either through lower overall energy production via increasing Pool prices. Essentially the same is true to the extent that a portfolio is short and elects to price its available assets at a low price in the expectation that Pool price will be lower.

Portfolio offer behavior often presents itself as changes in offer prices of assets in a broader portfolio where the changes cannot readily be tied to fundamentals such as changing natural gas prices, start-up costs etc. The changes are typically driven by the changes in the portfolio 'length' and participants' belief in the asset's ability to influence the prices, not the cost associated with the dispatch of the asset.

In situations when a change in portfolio 'length' is not consistent with the change in market 'length', the fidelity of price signal may be compromised. For example, an increase in Pool price may be observed when market supply is more abundant in relation to demand, because a 'long' portfolio is able to price certain assets out of merit and cause the Pool price to rise. A decrease in Pool price may be observed when the market loses generating units (due to planned or unplanned outages) and becomes tighter, because a 'short' portfolio is able to offer certain assets uneconomically and depress the Pool price.

Portfolio offer behaviour would seem to be quite common in Alberta and has a significant effect on Pool prices from time to time. The MSA is shortly embarking on a public consultation exercise to discuss its stance on this type of participant behaviour vis-à-vis section 6 of the EUA and the FEOC Regulation. The dialogue will start, as recommended by some participants, with an issues definition roundtable.

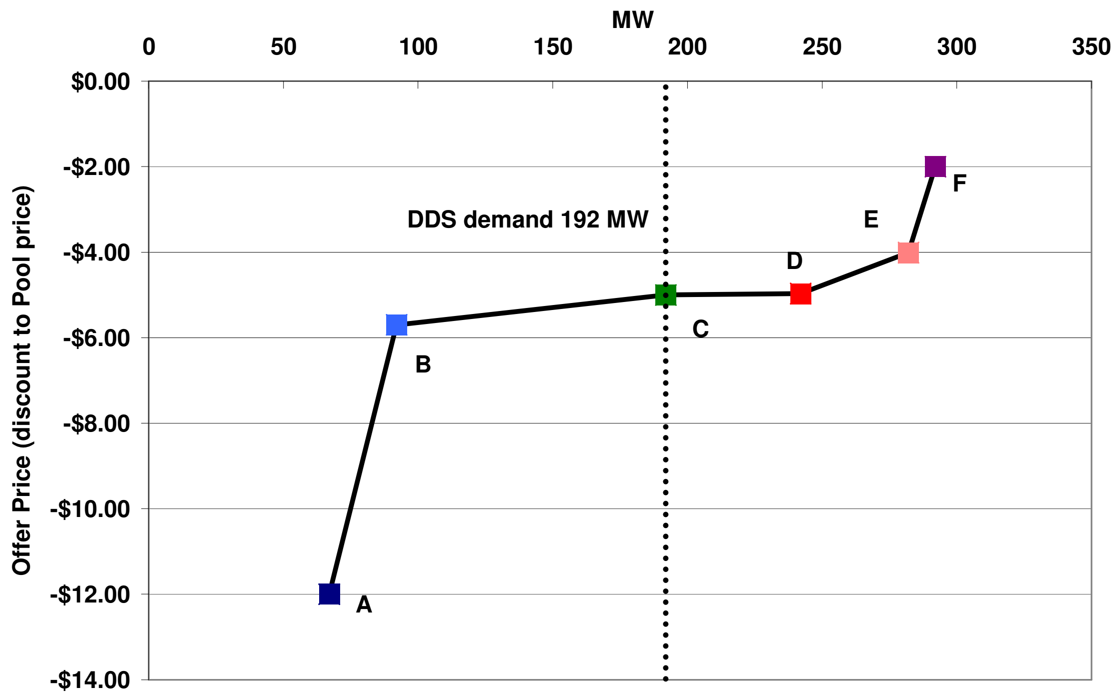
2.2 Dispatch Down Service (DDS) Offers

The DDS market is a pay-as-bid market. Each unit dispatched down is paid Pool price minus the discount at which the unit is offered (or $0 if this calculation results in a negative number).

Figure xi is an example of a DDS supply curve. Suppose the DDS demand was 192 MW and Participant A through Participant F offered DDS as follows:

Participant A: 67 MW@-$12/MWh
Participant B: 25 MW@-$6/MWh
Participant C: 100 MW@-$5/MW
Participant D: 10 MW@-$4.9/MWh
Participant E: 50 MW@-$4/MWh
Participant F: 40 MW@-$0.1/MW

Figure xi: DDS Supply Curve



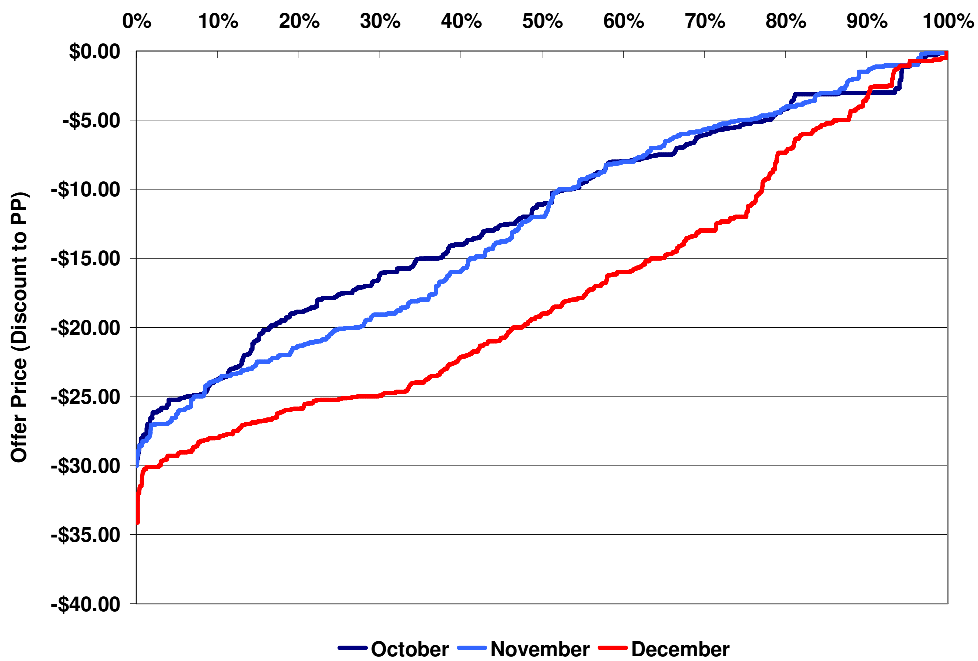
Although Participants A, B and C offered exactly the same DDS product, the pay-as-bid scheme resulted in them receiving different paid prices. If Participants A and B had offered at the same discount as Participant C, they would have received the same paid price as Participant C and wouldn't have left the money on the table.

With the historical DDS offers now being made public with 2 months delay, logically participants would use this information to estimate the offer price that would clear the market (the market clearing price). The participants whose opportunity costs of providing DDS are smaller than the estimated market clearing price are expected to move their offer prices up to the estimated market clearing price so when its offer is accepted, it would receive the same price as the other suppliers.

However, the duration curves of the DDS offers (Figure xii) didn't show reduced occurrence of deep discount over the months after the DDS merit order was published. It is likely that during the early stage of the publication, limited data are not sufficient to generate estimates of the market clearing price that are robust enough to guide the participants to offer DDS in such a way that they would not leave money on the table and at the same time would not risk the sales.

What Figure xii did show was an obvious downward shift of the DDS offers in December. Several DDS suppliers decreased their DDS offer prices in December.

Figure xii: Duration Curve of DDS Offers



The decrease in offer prices is likely attributed to the combination of significant reduction in DDS volume required and higher gas prices in December.

With the SVC being back in service in December, the amount of DDS required was reduced. Table iii shows the average volume of DDS that was dispatched in Q4/09, along with the monthly weighted average dispatched down offer price. With a smaller DDS market in December, market participants appear to have offered at greater discounts to ensure their DDS offers were accepted.

Table iii: Weighted Average of Accepted DDS Offer Price and Average Accepted DDS Volume - Q4/09

	October	November	December
Weighted Average of Accepted DDS Offer Price ($/MWh)	-$12.00	-$13.00	-$18.00
Average Accepted DDS Volume	147.00	135.00	89.00

Typically the majority of DDS market share is attributed to gas fired assets (Figure 24 in Appendix D). In December, higher natural gas prices (Figure 3 in Appendix A) reduced the opportunity cost of gas fired units to provide DDS service and enabled them to offer greater discount in the DDS market.

Although Table iii shows that the weighted average DDS offer in December was $5 to $6/MWh lower than October and November, the average price paid to DDS suppliers in December was higher (Table 3 in Appendix D). This is because in December, the Pool price was higher than in October and November (Table 1 in Appendix A). The higher Pool prices allowed the DDS revenue to increase in December notwithstanding deeper discounts of DDS offers.

3 AESO TECHNICAL DIFFICULTIES ON DECEMBER 15, 2009

On Tuesday, December 15, 2009, between approximately 4:25pm and 6:30pm, the AESO experienced technical difficulties with their internal network systems. This resulted in the Energy Trading System (ETS) and web based market reports being unavailable. The problems were further compounded by unanticipated problems with the Customer Information Line (CIL) that is intended to provide updates and market information in the event of ETS and web based reports not being available. Further details of the events and the steps taken to improve the resiliency of the AESO systems are given in two notices posted on the AESO's website.[9]

The MSA notes that network problems such as those experienced on December 15, 2009 severely hamper the ability of the real time market to function. As part of the MSA's own enquiries into these events we requested from the AESO further details around what market participants should expect when a network failure occurs and the CIL becomes market participants' only source of information. The AESO provided the following description (See Section 3.1 below) and the MSA believes this information may be helpful to some market participants in the event that problems recur. Participants should note the importance of keeping telephone contact information up-to-date (in order to receive the Ventriloquist broadcast) and should review the information typically included on the Customer Information Line to ensure it meets basic needs with regard to market functioning.

The MSA notes that the events of December 15 occurred around a forecast peak demand for the year. For some market participants, such as those whose transmission charges relate to consumption during the monthly 15 minute coincident peak, timely information about load at times of potential peak is very important for their commercial operations. This was brought to our attention by one such participant. The MSA has recommended that the AESO include system load information on the CIL, either in most cases or at times when approaching peaks.

[9] For further details see http://www.aeso.ca/downloads/Network_Issue_(Dec-15-09)_(1).pdf and http://www.aeso.ca/downloads/dec15followup.pdf.

3.1 AESO On-Call Process – Ventriloquist and the Customer Information Line (CIL)

The AESO has two key tools for communicating with market participants in the event of an unexpected problem with its critical systems, or a system emergency requiring immediate notification to participants. These are Ventriloquist and the CIL.

Ventriloquist is an automatic telephone message system sent out to participants and the CIL is a phone-in line where the caller can listen to a pre-recorded message. A Ventriloquist message is sent to the corporate contacts as listed in ETS, as well as the contacts from the participant's User Profile in ADaMS (i.e. 24 hour and manager phone numbers). It is the participant's responsibility to ensure their contact information remains current.

A Ventriloquist message will provide participants with the information the AESO has available at that time, given the circumstances, such as:

- The individual sending the message, along with the date/time of recording;
- Which systems are being impacted, i.e. ETS, ADaMS, AESO Website, etc;
- How this is impacting participants (i.e.; Pool Price and/or System Marginal Price (SMP) cannot be posted, ETS is unavailable, dispatch instructions cannot be issued through ADaMS, etc.);
- Any steps required from the participants, i.e.; fax restatements to SCC;
- Last available Pool Price and/or SMP (if it has not been posted and is available to provide); and
- Directs participants to the CIL at 403-214-7508 for further updates on the status of the situation and further updates to the Pool Price and/or SMP, if required and available.

The CIL will provide further recorded updates related to the situation identified in the Ventriloquist message. Participants cannot leave messages on the CIL as it is intended for information purposes only. Typically, the information provided on the CIL is:

- The date and time of the recorded update;
- A brief description of the systems impacted and/or the event that has occurred;
- The last hourly Pool Price and the most recent SMP (if available);
- Any steps required from participants, i.e. fax restatements to SCC;

- Advises participants that the CIL will be updated accordingly to provide regular updates on Pool Price and SMP, if available;
- Once the issue has been resolved, the CIL will again be updated to reflect this.

It is the participant's responsibility to continually check the CIL for further updates until the situation has been resolved. If participants have any questions, they may contact AESO FirstCall at 1-888-588-AESO (2376), during business hours.

4 MSA ACTIVITIES

4.1 MSA Strategic Framework

Throughout Q4/09, the MSA developed its Strategic Framework in which the MSA Vision, Mission and Values are stated. The MSA Vision sets out what we aspire to achieve. The MSA Mission provides a path to realize our Vision. The MSA Value consists of beliefs that are shared among our stakeholders, are deeply held and do not change over time. The full text of the MSA Strategic Framework can be found at: http://www.albertamsa.ca/files/MSA_Vision_Mission_Values_2009.pdf

4.2 Completion of the 2005 Enmax Import Investigation

In Q4/09, the MSA concluded the 2005 Enmax Import Investigation. It is the MSA's view that the imports during the period at issue did not amount to uneconomic imports, the behaviour was not contrary to the guidance provided with respect to uneconomic importing and there was no breach of Section 6 of the EUA. An explanation of the matters at issue and the reasons for the MSA findings can be found at: http://www.albertamsa.ca/files/Enmax_2005_Investigation_Report_120409.pdf

4.3 AUC Proceedings

Listed below in chronological order (according to filing or commencement date) are the various AUC proceedings of note involving the MSA during Q4/09. Some proceedings have carried forward from prior months.

MSA v. ENMAX Corporation, ENMAX Energy Corporation and ENMAX Energy Marketing Inc. (Application 1605352, Proceeding ID 269)

The MSA filed this Application on July 21, 2009 seeking an administrative penalty against the ENMAX parties (ENMAX) for alleged contravention of Section 55(4) of the *Electric Utilities Act* (EUA), Section 46(4) of the AUCA, and Sections 3(1) and 3(2) of the Alberta *Market Surveillance Regulation*. The allegations arose in relation to certain responses provided by ENMAX to MSA inquiries before and during an investigation.

The AUC issued a notice on August 10, 2009, indicating that it proposed to handle the proceeding in two stages; the first as to whether any contraventions had occurred, as alleged, and the second to determine the appropriate administrative penalty if a contravention is found. The AUC invited the parties to comment on the proposed process and other matters.

As a result of preliminary submissions by the parties regarding process, on September 11, 2009 the AUC set a timetable for the filing of any motions and related responses on preliminary matters. Motions were filed by ENMAX September 22, 2009, and responded to by the MSA. On October 21, 2009 the AUC issued its ruling on preliminary matters, including as to the extent of particulars, applicable standard and burden of proof, and the AUC also set out its timetable for the proceeding.

ENMAX filed its response to the MSA Application on November 5, 2009. Based upon discussions between them, the parties then requested that the AUC adjourn the impending hearing to allow them more time to pursue a possible settlement. The AUC agreed to the adjournment.

On December 9, 2009 the parties submitted for AUC approval a proposed Consent Order, and also requested that the Consent Order and related settlement agreement materials be held confidential until the Consent Order is approved, for reason that they set out without prejudice discussions between the parties. On January 12, 2010 the AUC notified the parties of its concern that the materials should be filed on the public record. The AUC noted that a proceeding had already been commenced and a hearing date set, then adjourned to allow the parties to pursue settlement. The AUC had set a deadline for the parties to file settlement materials; accordingly, in the view of the AUC, the proposed Consent Order materials must be filed on the public record to ensure transparency and to show that the parties have met the direction of the AUC. The AUC also advised that any requested confidentiality for parts of the materials should be brought by way of motion pursuant to AUC Rule 001 and Rule 014. On that basis the Consent Order and related settlement agreement materials were returned to the parties for re-filing.

On January 15, 2010 the parties re-filed the Consent Order and related settlement materials without any request for confidentiality.

Consultation on MSA Proceedings before the AUC (AUC Bulletin 2009-15, AUC Bulletin 2009–16)

In June, 2009 the AUC issued Bulletin 2009–15, indicating that it was considering a consultation process to facilitate discussion on the potential regulatory treatment of procedural fairness and due process issues associated with proceedings brought before the AUC by the

MSA. The proposed topics were wide ranging and of considerable significance to the MSA. Comments were invited from interested parties, and accordingly were submitted by the MSA.

Later that month the AUC issued Bulletin 2009-16, initiating the consultation and attaching for comment two discussion papers covering various related topics. The MSA accordingly provided written comments in respect of the two discussion papers.

As part of the consultation process the AUC scheduled two roundtable meetings, to allow discussion of the topics and of comments received from the various stakeholders. Those roundtable meetings occurred in September and October, and were followed by the opportunity to provide further comments in writing. The MSA participated actively in the roundtable meetings and also submitted further written comments.

It is anticipated that the AUC will provide its views and decisions on the consultation matters in 2010, including as to new or revised AUC Rules contemplated.

MSA v. Syncrude Canada Ltd. (Application 1605552)

On September 22, 2009 the AUC issued Decision 2009-144, confirming a Specified Penalty issued by the MSA and ordering Syncrude to pay the amount owing ($8,000.00) within 30 days (see Proceeding ID 168).

The issuance of Decision 2009-144 meant that the MSA was entitled to apply for its Costs in relation to that proceeding, pursuant to AUC Rule 015 and Section 66 of the AUCA. Accordingly, on October 21, 2009 the MSA filed its Application for Costs (Application 1605552).

In accordance with AUC Rule 015, the Application sought recovery of the legal costs incurred in relation to the hearing as well as costs relating to MSA witnesses. Rule 015 sets out a Schedule – Scale of Costs which applies and governs the calculation of recoverable costs.

On October 23, 2009 the AUC issued a notice confirming receipt of the Application and advising that it would be using an updated version of AUC Rule 015 in respect of the proceeding. The claim for costs in the Application had been calculated based upon the version of AUC Rule 015 posted on the AUC website; an updated version had been approved by the AUC but not yet posted to its website. Hence the AUC decided that it would use the updated version, which technically applied to the matter.

On December 21, 2009 the AUC issued a notice which set out the process to be used for the proceeding, including a direction to the MSA and Syncrude to make submissions on certain "principles" which might provide guidance in respect of costs awards and setting out timelines for filing by Syncrude of its response to the Application and an opportunity for the MSA to make reply. The ultimate deadline for submissions was established by the AUC as January 22, 2010. The parties then await a determination on the Application, as well as other guidance which might be issued by the AUC insofar as cost awards.

As elaborated upon in the MSA's submissions to the AUC, this does not signal an initiative by the MSA to routinely seek costs, nor use costs as a punitive measure against participants. Rather, the MSA would exercise this discretion selectively, for example, in situations where in our view a proceeding is unnecessary because the law is settled. To not seek costs (and only proceeding costs as distinct from the MSA's normal costs of monitoring and investigation) in that type of proceeding is effectively asking all market participants to subsidize the wasteful litigation of a single participant.

MSA v. ASTC Power Partnership (Application 1605688, Proceeding ID 415)

This Application was filed by the MSA on December 7, 2009, seeking approval of a Settlement Agreement pursuant to Section 44 and Section 51 of the AUCA. The MSA requested on behalf of the parties that the filed materials be held confidential and made public only if the AUC approved the Settlement Agreement, for reason that the materials contained "without prejudice" communications between the parties.

On December 18, 2009 the AUC issued a notice indicating its view that applications are generally to be filed on the public record to ensure transparency of process from the inception of a matter. Accordingly, the AUC returned the Application and Settlement Agreement to the parties for re-filing, along with the filing of any separate requests for confidentiality pursuant to AUC Rule 001 and Rule 014.

The parties are reviewing their options in respect of the guidance issued by the AUC, insofar as the handling and treatment of without prejudice settlement communications in the context of an AUC proceeding.

4.4 Code of Conduct

As part of its mandate under the *Alberta Utilities Commission Act* and other enactments, the MSA monitors the retail electricity market in Alberta, to help ensure its fair, efficient and openly competitive operation.

The electricity Code of Conduct Regulation (Code) was enacted under the *Alberta Electric Utilities Act* to help ensure a level playing field for retailers and thereby promote a competitive retail electricity market. Specifically, the Code governs the interactions between owners of electricity distribution systems (owners) and their affiliated retailers such that affiliated retailers maintain no preferential status over other retailers by virtue of their relationship with an owner.

The Code contemplates that owners and affiliated retailers will undergo a compliance audit on an annual basis, within the oversight of the MSA.

There is a degree of discretion available to the MSA as to how such auditing is carried out.

In 2009, a total of five market participants (owners/affiliated retailers) were audited. The period being tested was July 1, 2008 through June 30, 2009. The audit testing focused on sections of the Code which address adherence to compliance plans and accuracy of compliance reporting.

The audit testing plan was carried out through on-site visits between August and September, 2009. During Q4/09, audit reports were drafted and then reviewed with the relevant parties, after which audit reporting for each was finalized.

Generally speaking, the Code audits showed a good level of compliance amongst the parties tested. Further detail can be found in the related Notice posted on the MSA website December 7, 2009 (http://www.albertamsa.ca/1057.html).

4.5 The MSA Budget

In Q4/09, the MSA received approval for its 2010 budget. The amount of the budget is $3,101,114, comparable to that of 2009. Based on the AESO estimated volume for 2010, the MSA's portion of the trading charge is approximately $0.0263/MWh. The notice regarding to the MSA 2010 Budge can be found at: http://www.albertamsa.ca/files/MSA_Notice_2010_Budget.pdf

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]
Oct-09	34.93	41.57	25.73	12.76	37%
Nov-09	50.16	65.07	31.57	63.57	127%
Dec-09	53.86	64.93	38.52	65.13	121%
Q4-09	**46.27**	**56.99**	**31.94**	**53.55**	**116%**
Jul-09	41.39	53.98	23.94	42.29	102%
Aug-09	34.60	45.45	20.85	36.91	107%
Sep-09	73.25	113.27	18.48	168.40	230%
Q3-09	**49.49**	**70.68**	**21.11**	**102.86**	**208%**
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%
Q4-08	**95.16**	**121.23**	**60.29**	**150.99**	**159%**

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

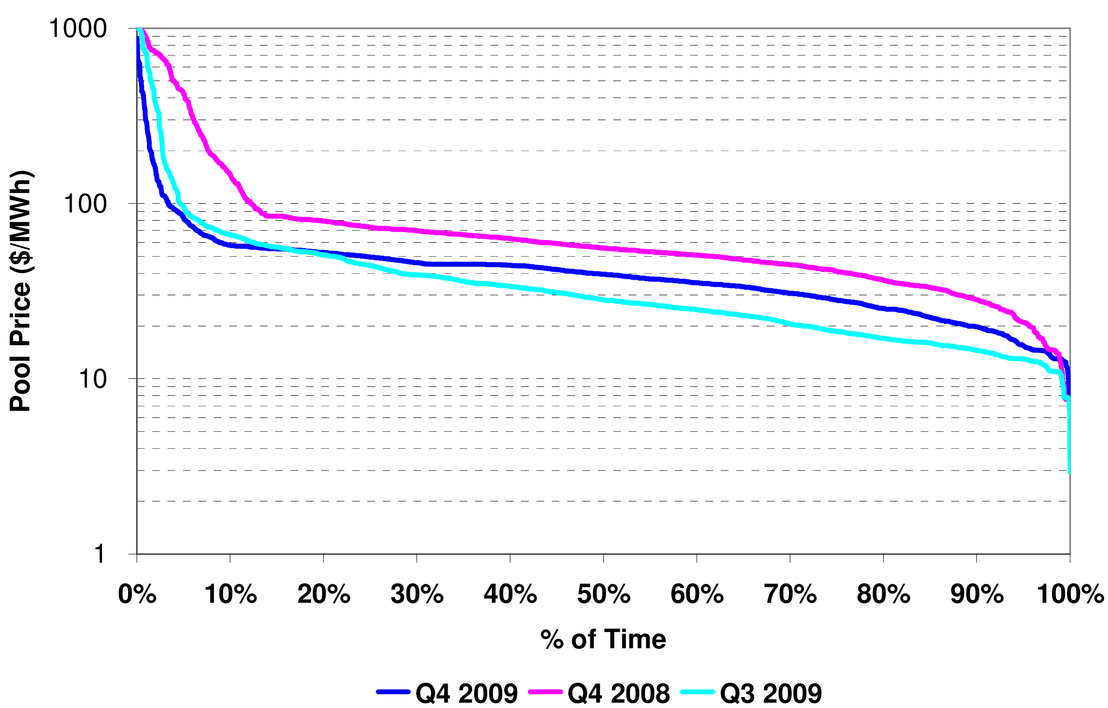


Figure 2 - Pool Price with Pool Price Volatility

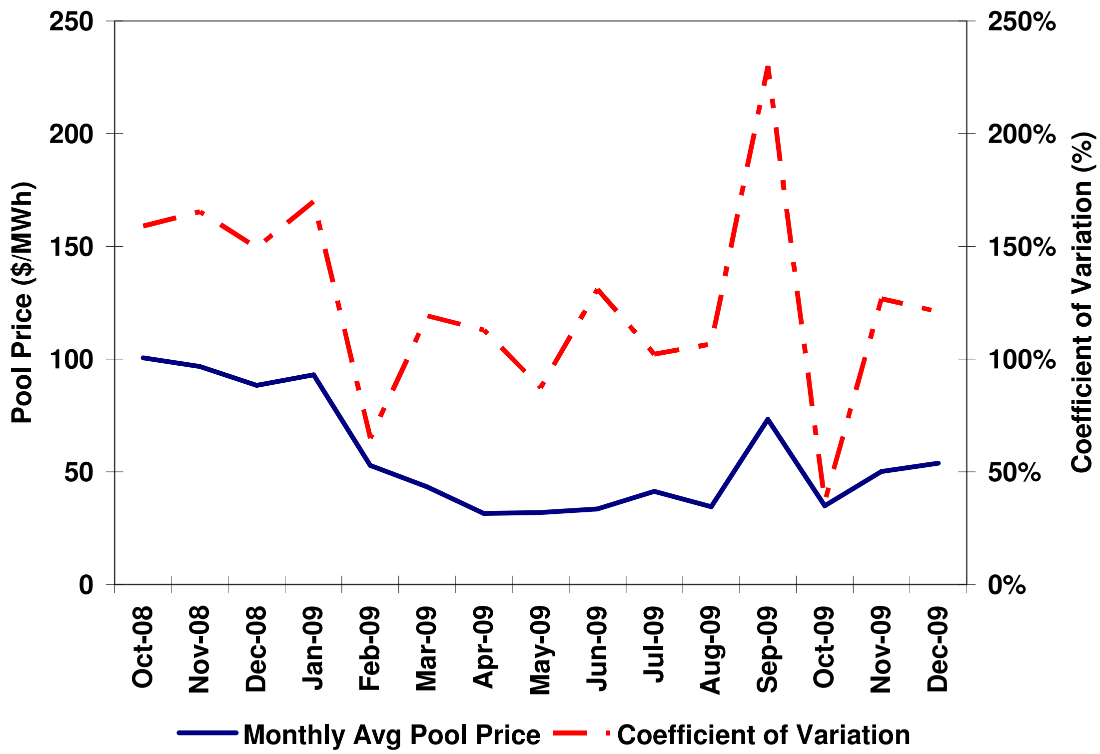


Figure 3 - Pool Price with AECO Gas Price

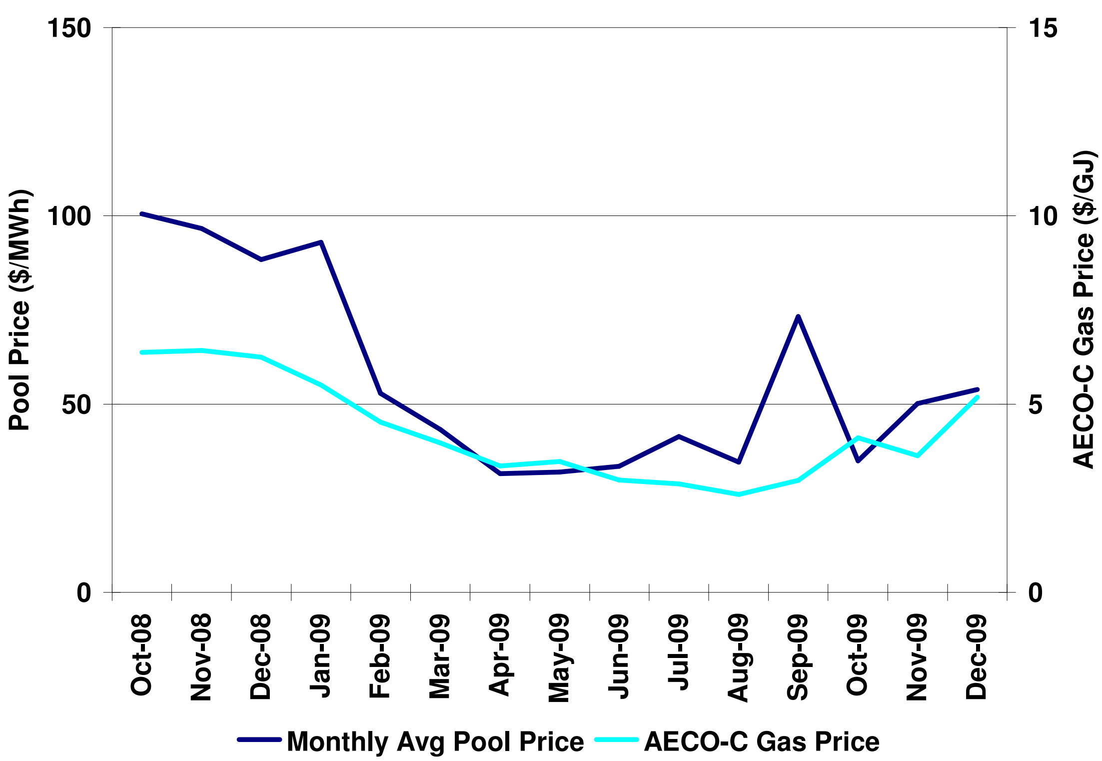


Figure 4 - Price Setters by Pool Participant (All Hours)

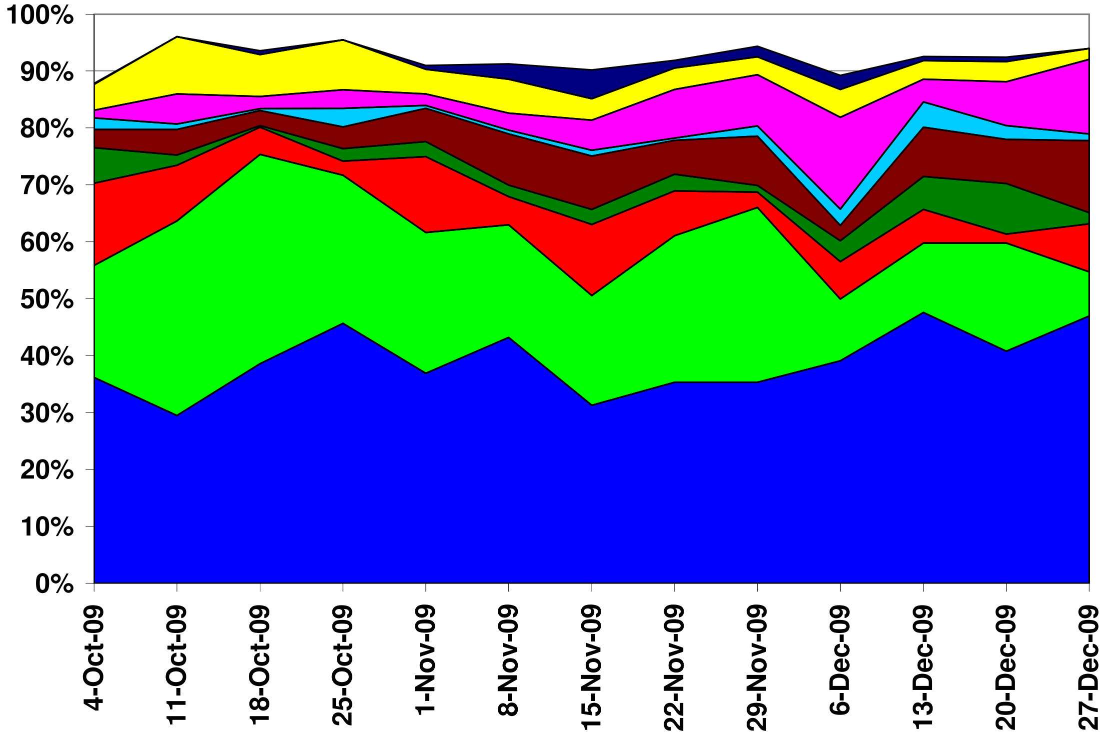


Figure 5 - Price Setters by Fuel Type (All Hours)

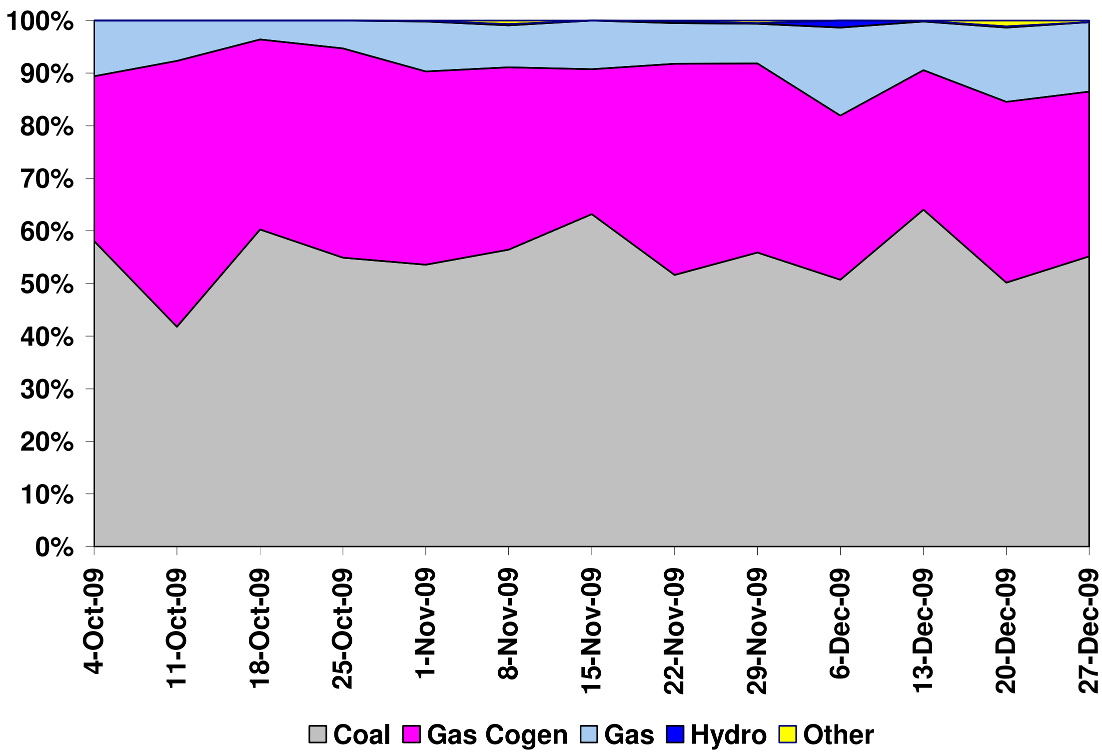


Figure 6 - Heat Rate Duration Curves (All Hours)

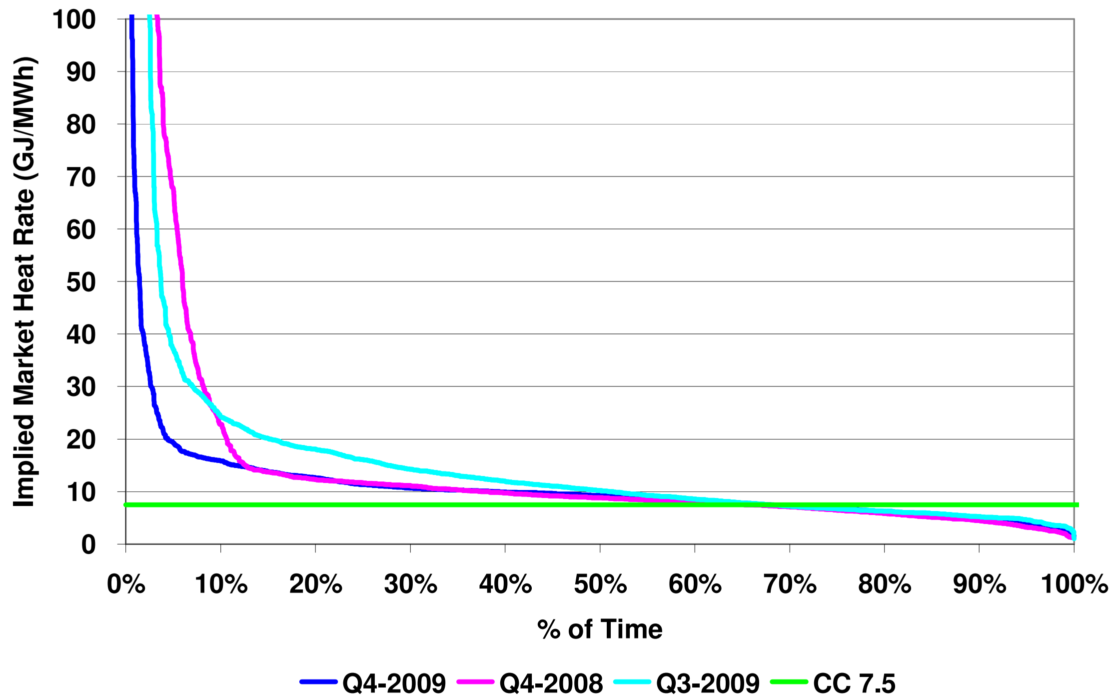


Figure 7 - Implied Market Heat Rates On-Peak

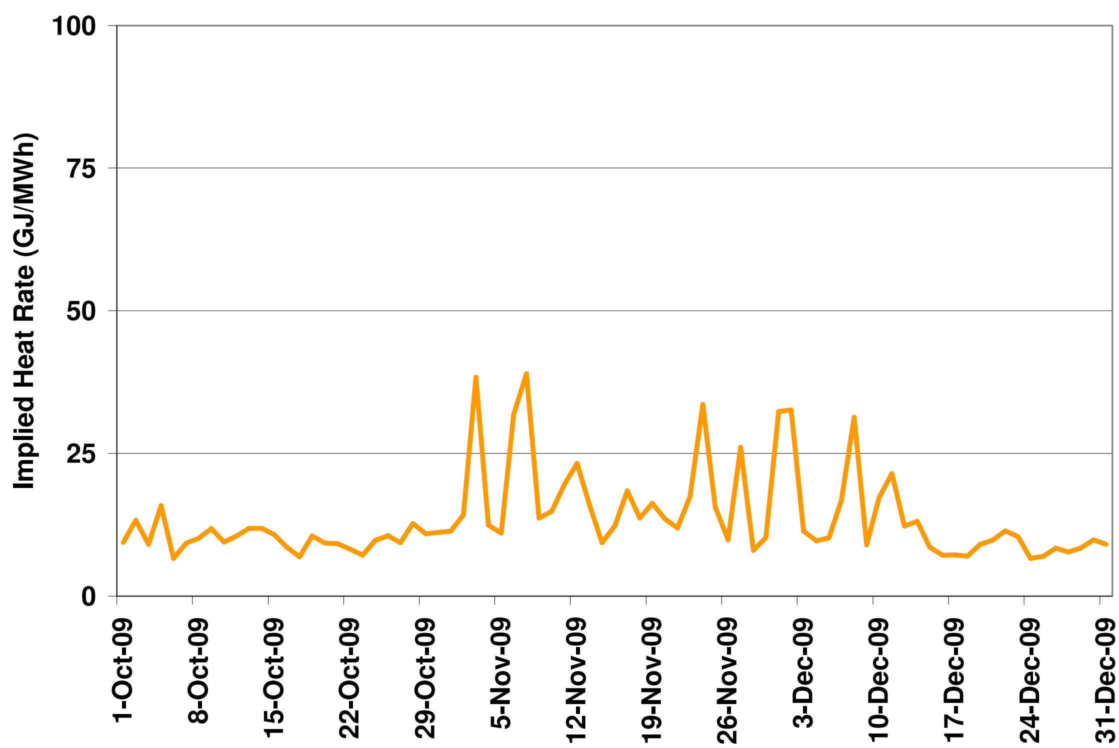
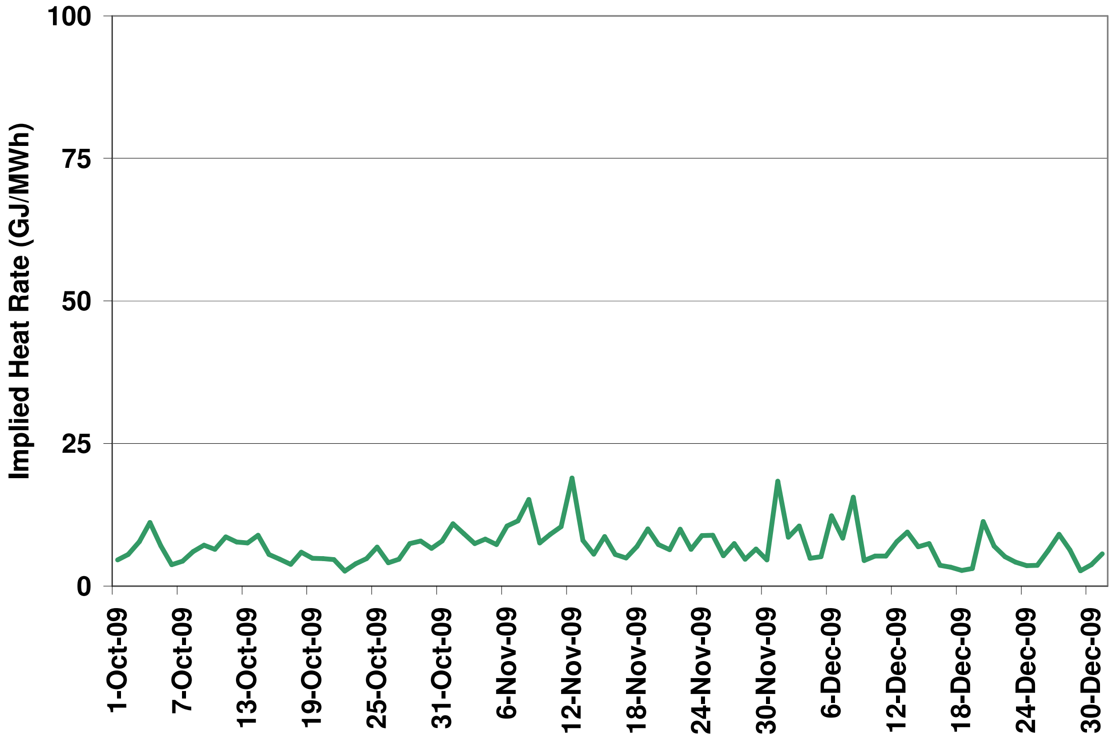


Figure 8 - Implied Market Heat Rates Off-Peak

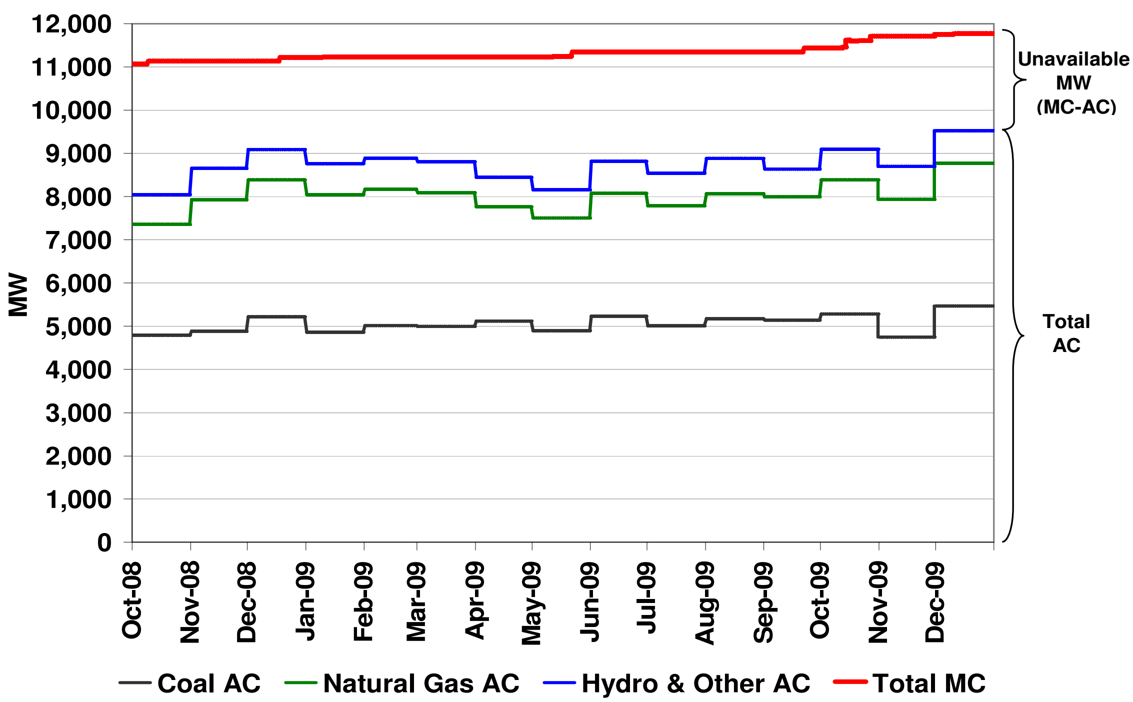


APPENDIX B – SUPPLY AVAILABILITY METRICS

Table 2: Availability Factor and Capacity Factor

Fuel Type	Quarter	Average MC [A] (MW)	Average AC [B] (MW)	Availability Factor [C]=[B]/[A]	Generation [D] (GWh)	Capacity Factor [E]= [Dx1000]/([A]xhrs)
All Fuels	Q4/09	11,671	9,111	78%	16,228	63%
	Q3/09	11,357	8,543	75%	15,330	61%
	Q4/08	11,138	8,594	77%	15,676	64%
Coal	Q4/09	6,048	5,173	86%	10,677	80%
	Q3/09	6,011	5,008	83%	10,241	77%
	Q4/08	6,011	4,964	83%	10,544	79%
Natural Gas	Q4/09	4,706	3,194	68%	5,129	49%
	Q3/09	4,431	2,779	63%	4,600	47%
	Q4/08	4,212	2,921	69%	4,715	51%
Hydro & Other	Q4/09	917	745	81%	423	21%
	Q3/09	915	755	83%	490	24%
	Q4/08	915	709	77%	417	21%
Wind	Q4/09	563	n/a	n/a	517	42%
	Q3/09	502	n/a	n/a	202	18%
	Q4/08	497	n/a	n/a	456	42%

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



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 10 - Active Settlement Prices - All Markets (NGX and OTC)

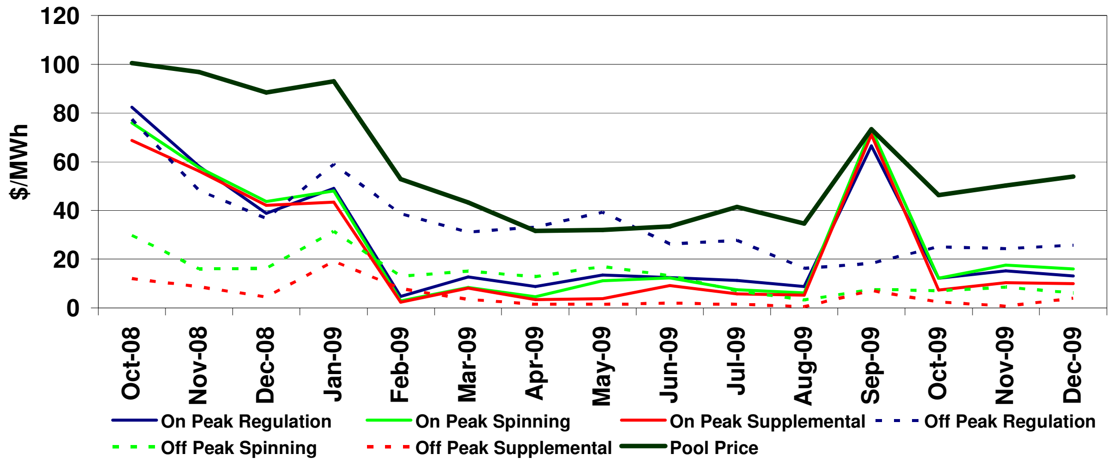


Figure 11 - Standby Premiums – All Markets (NGX and OTC)

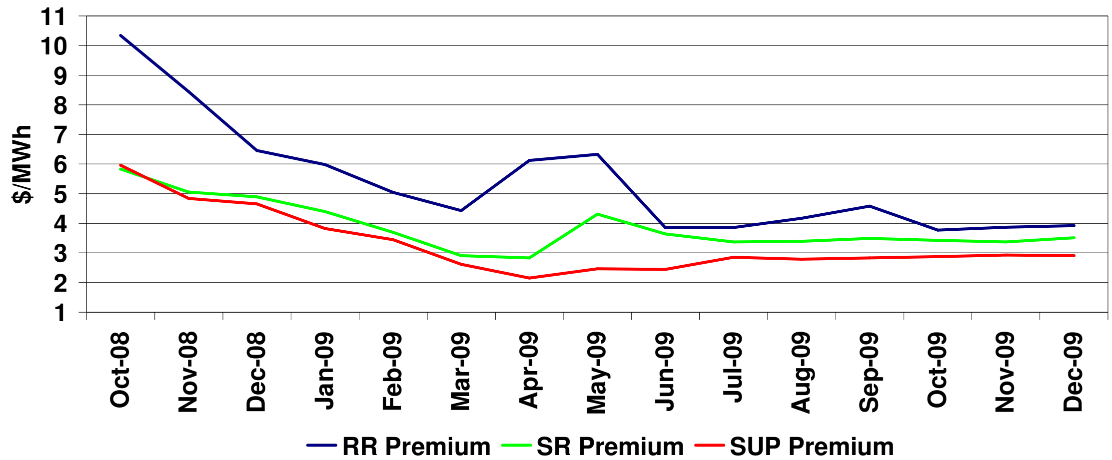


Figure 12 - Standby Activation Prices – All Markets (NGX and OTC)

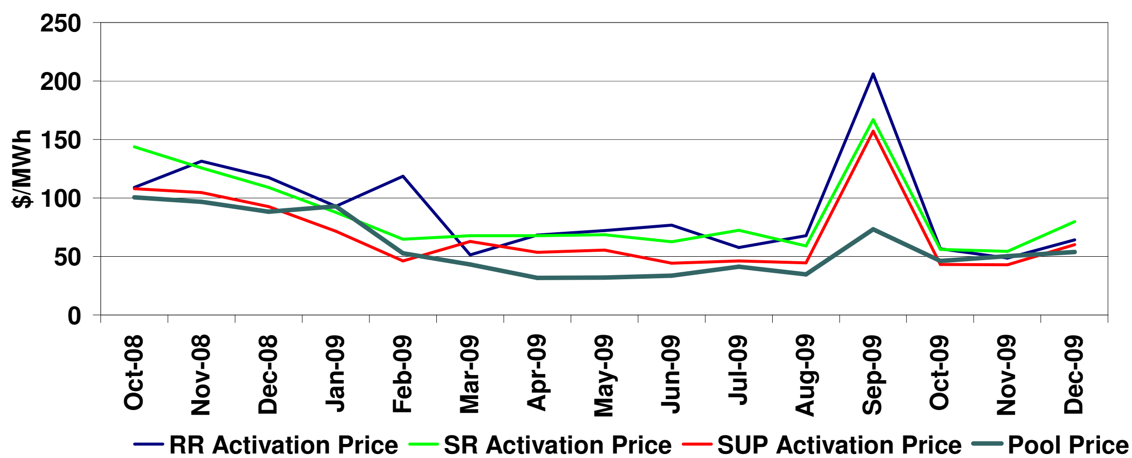


Figure 13 - Standby Activation Rates

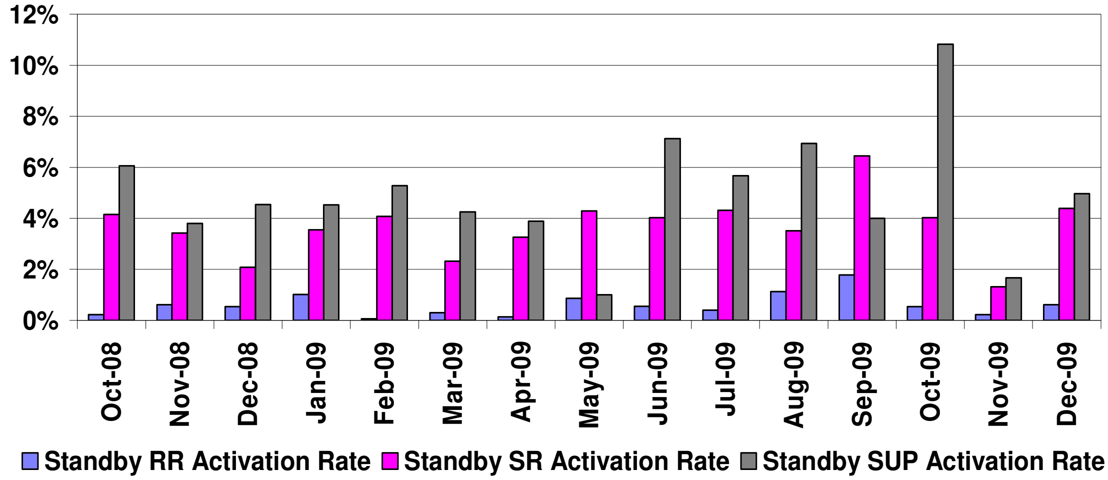


Figure 14 - OTC Procurement as a % of Total Procurement

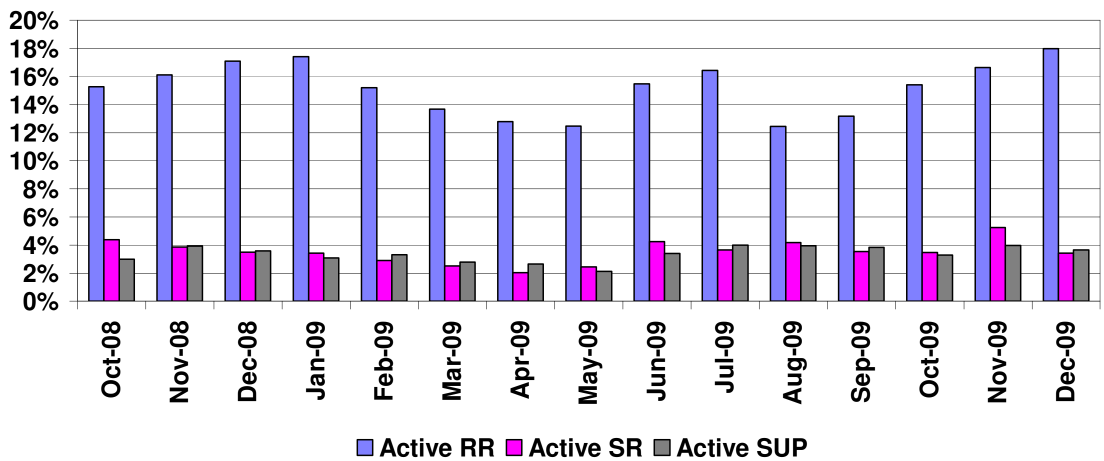


Figure 15 - Active Regulating Reserve Settlement by Market

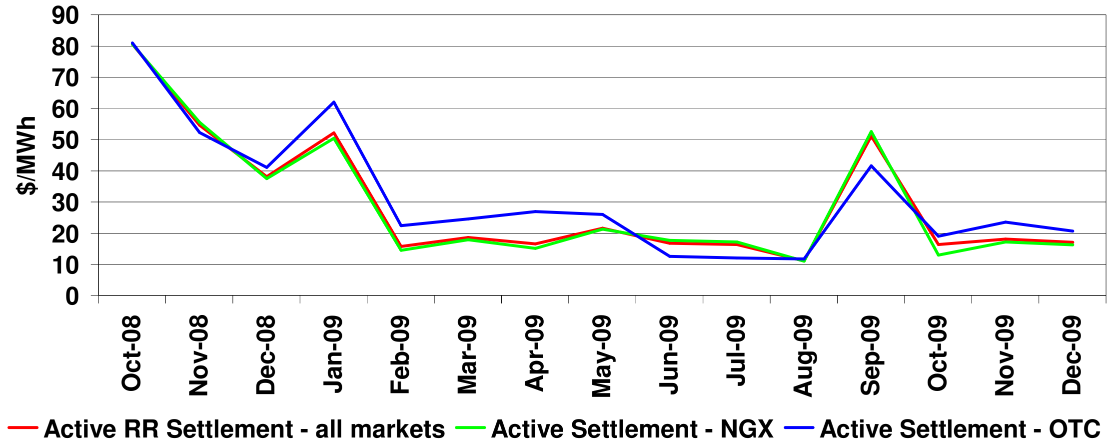


Figure 16 - Active Spinning Reserve Settlement Price by Market

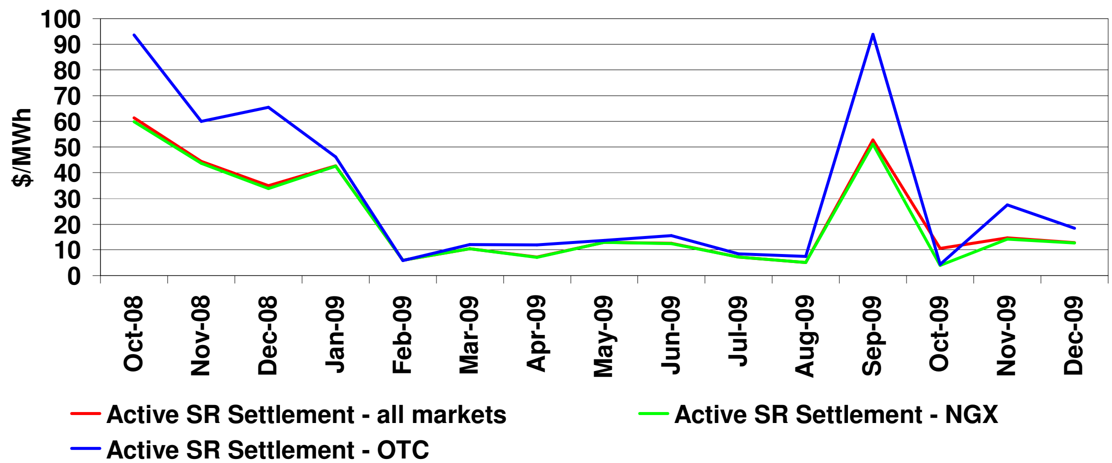


Figure 17 - Active Supplemental Reserve Settlement Price by Market

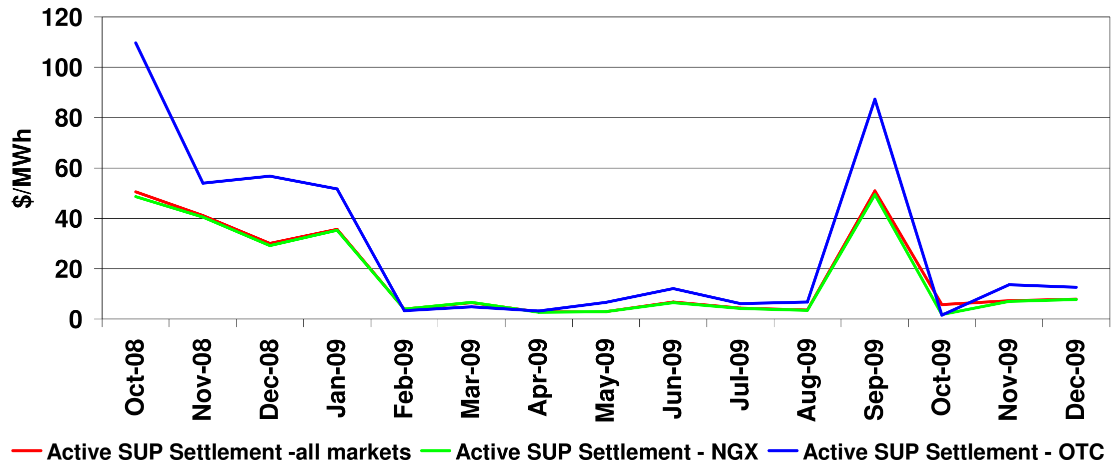


Figure 18 - Active Regulating Reserve Market Share by Fuel Type

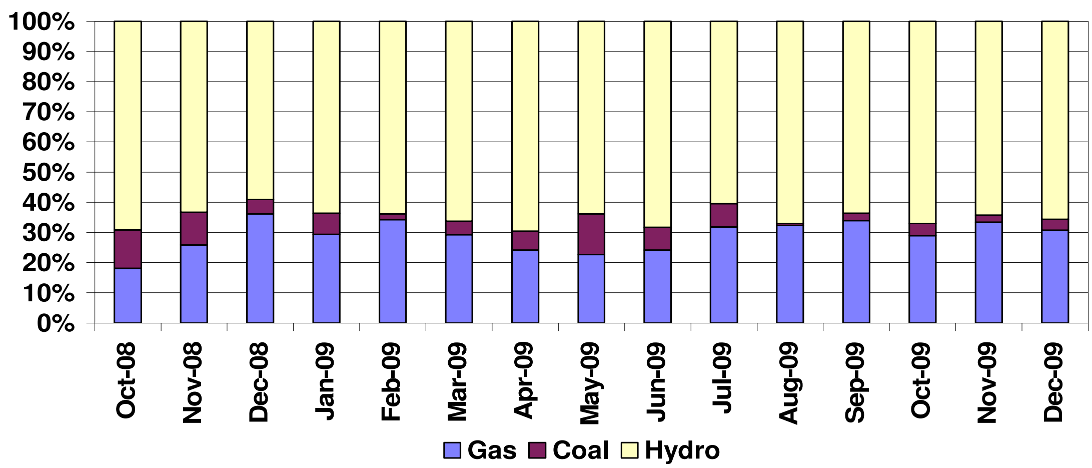


Figure 19 - Active Spinning Reserve Market Share by Fuel Type

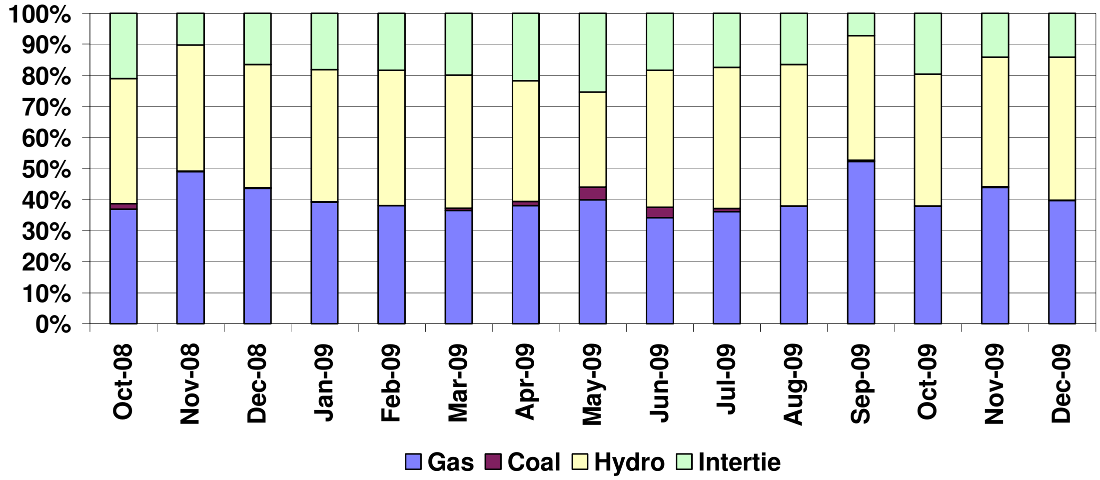
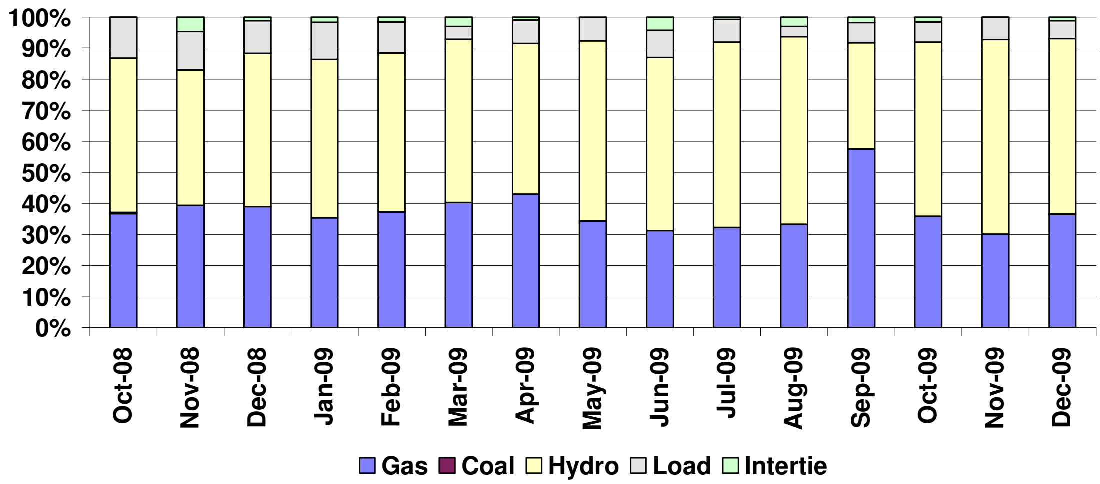


Figure 20 - Active Supplemental Reserve by Fuel Type



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]
October	$2.04	109,655	4,839,422	$0.42	$18.57
November	$1.96	97,051	4,730,522	$0.41	$20.15
December	$1.38	64,938	5,196,443	$0.26	$21.19
Total	$5.37	271,643	14,766,387	$0.36	$19.76

Figure 21 - Average Daily TMR, Available, Eligible & Dispatched DDS Volumes (MW)

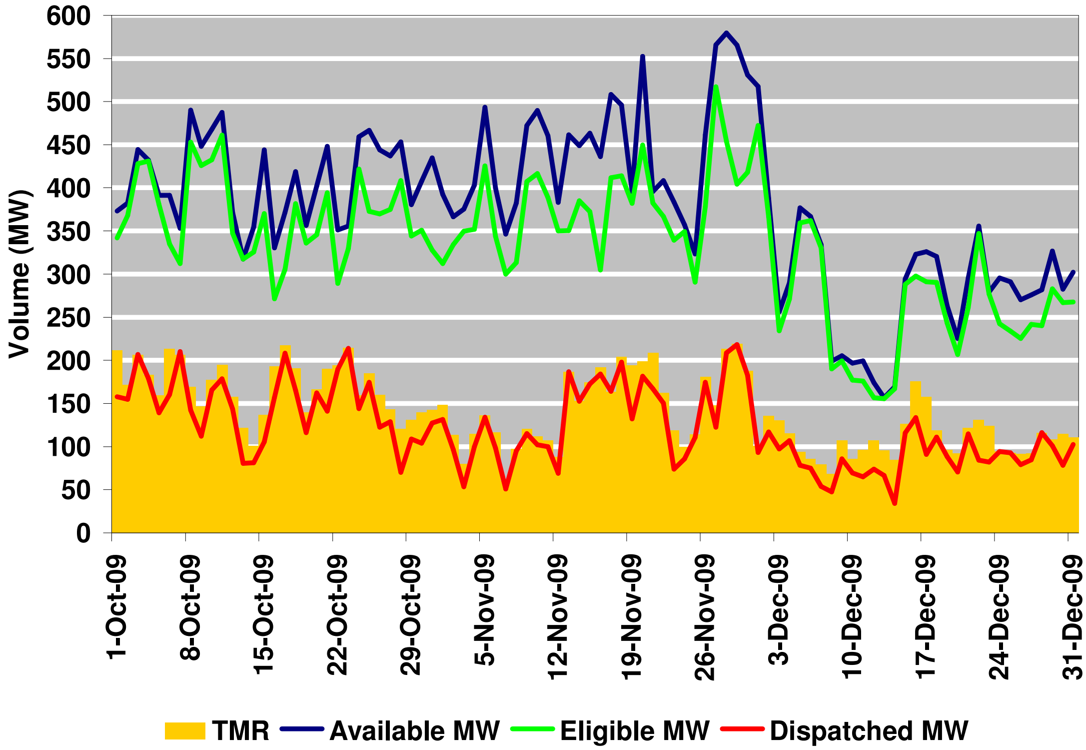


Figure 22 - Average Daily DDS Dispatched and Constrained Down Volume (MW)

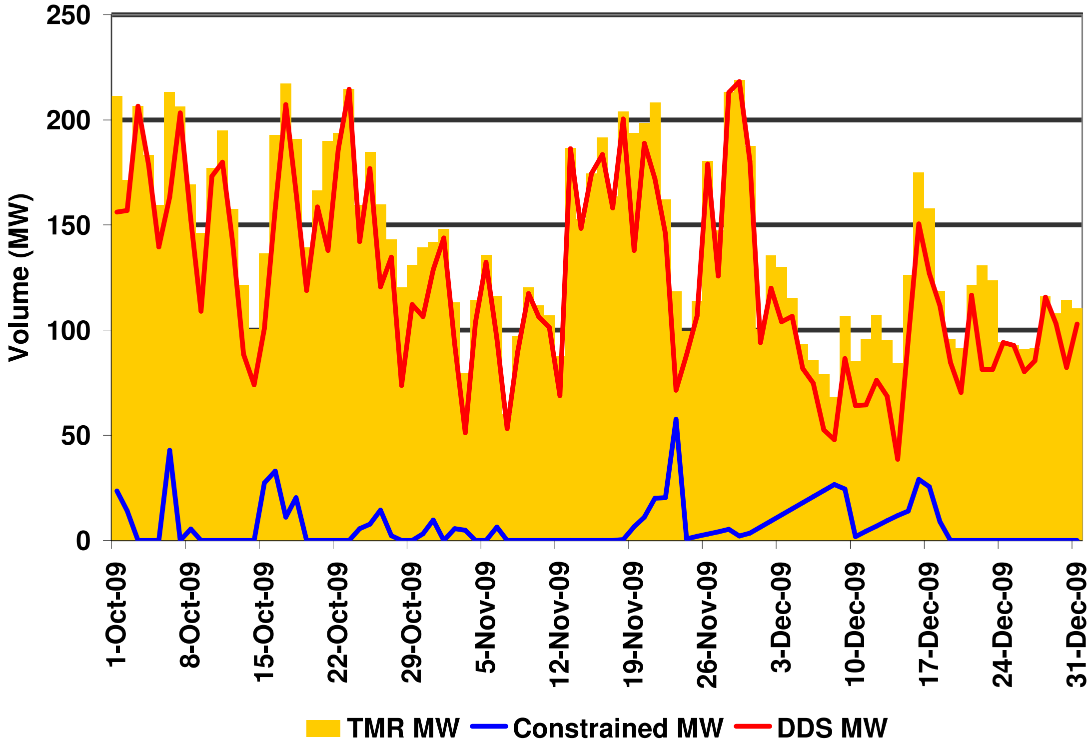


Figure 23 - Average Weekly DDS Market Share by Submitting Participants

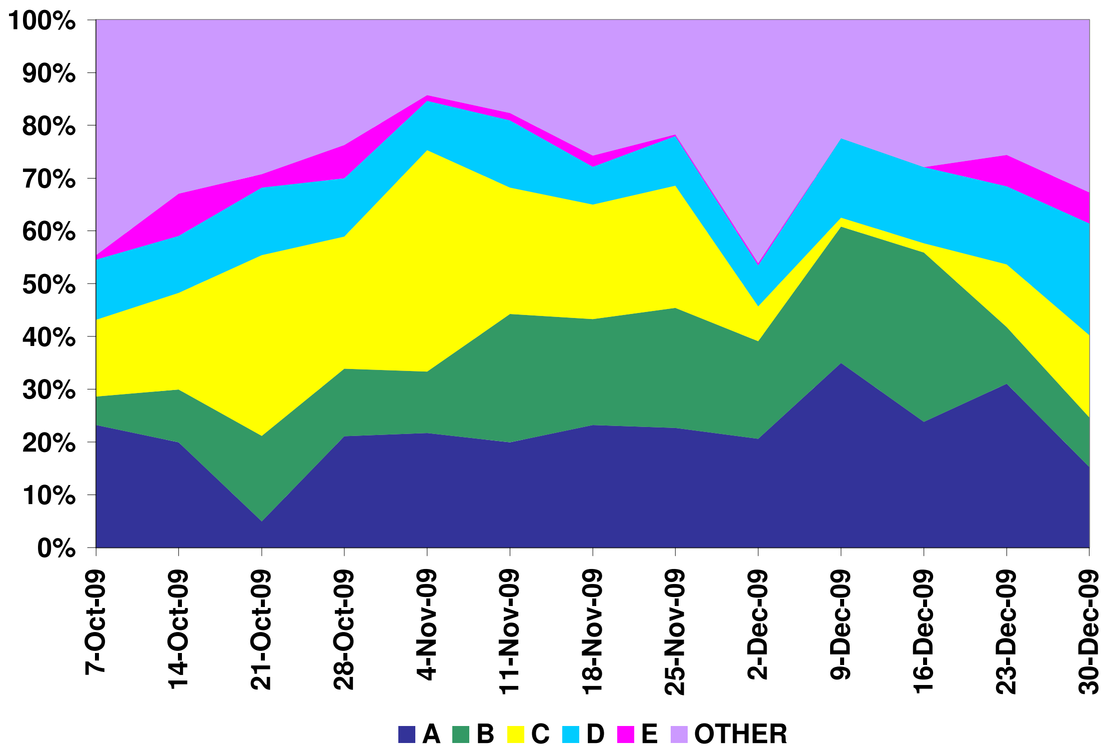
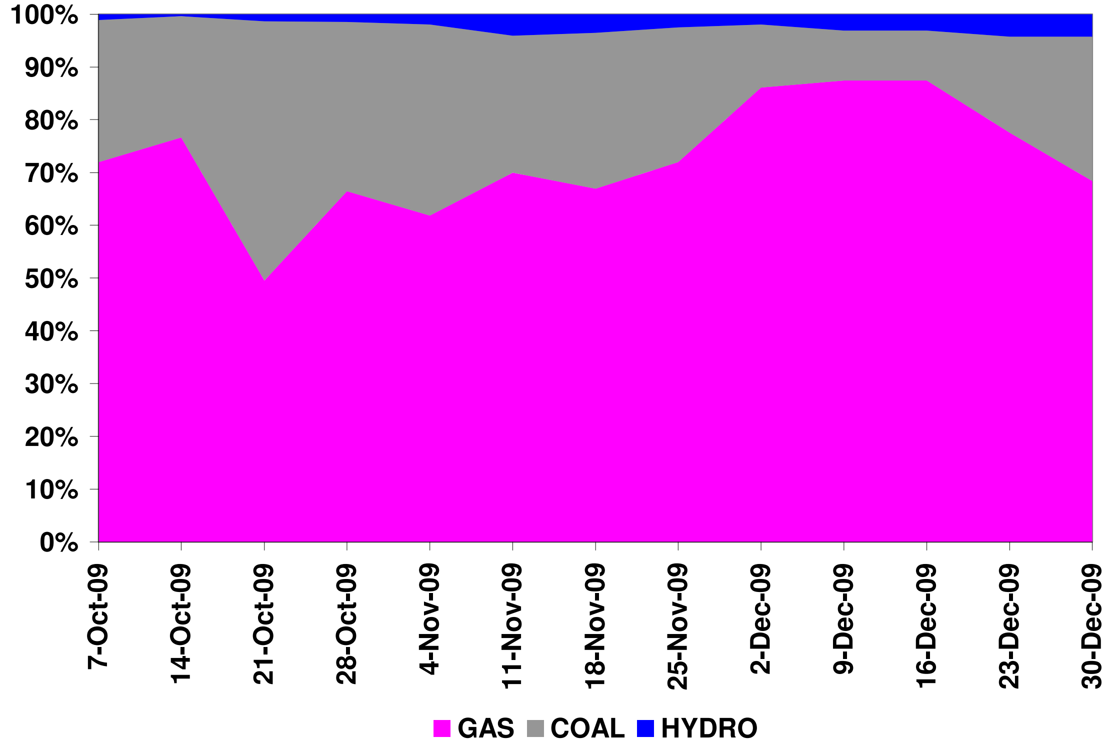


Figure 24 - Average Weekly DDS Market Share by Fuel Type



APPENDIX E – INTERTIE METRICS

Figure 25 - Intertie Utilization

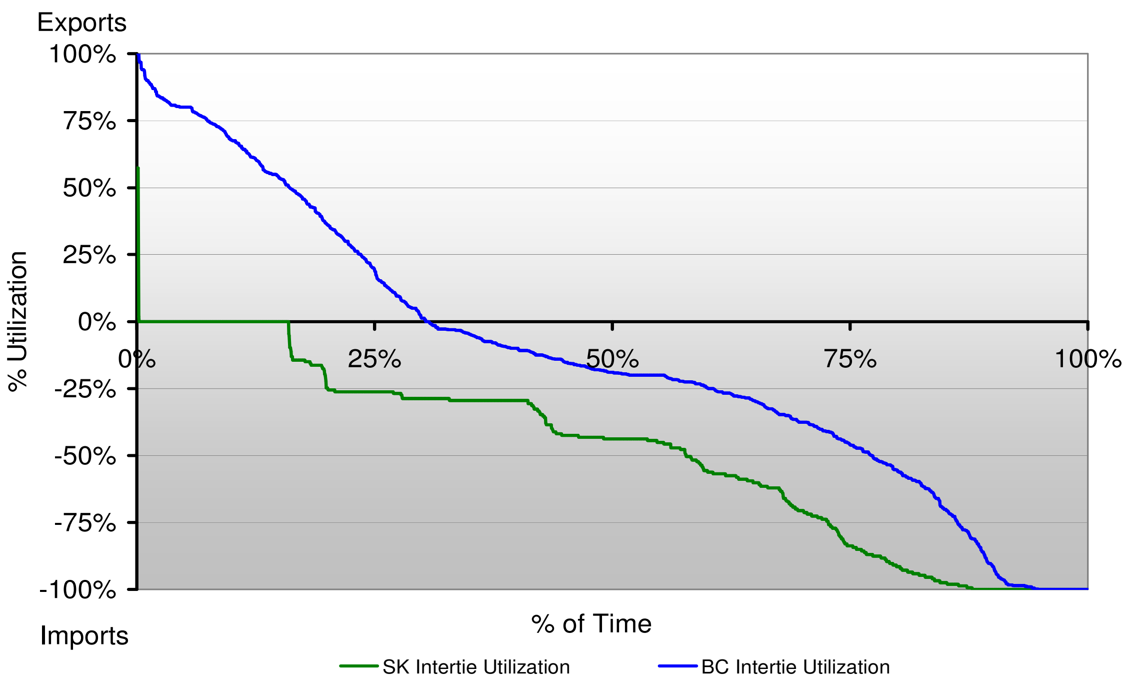


Figure 26 - On-Peak Prices

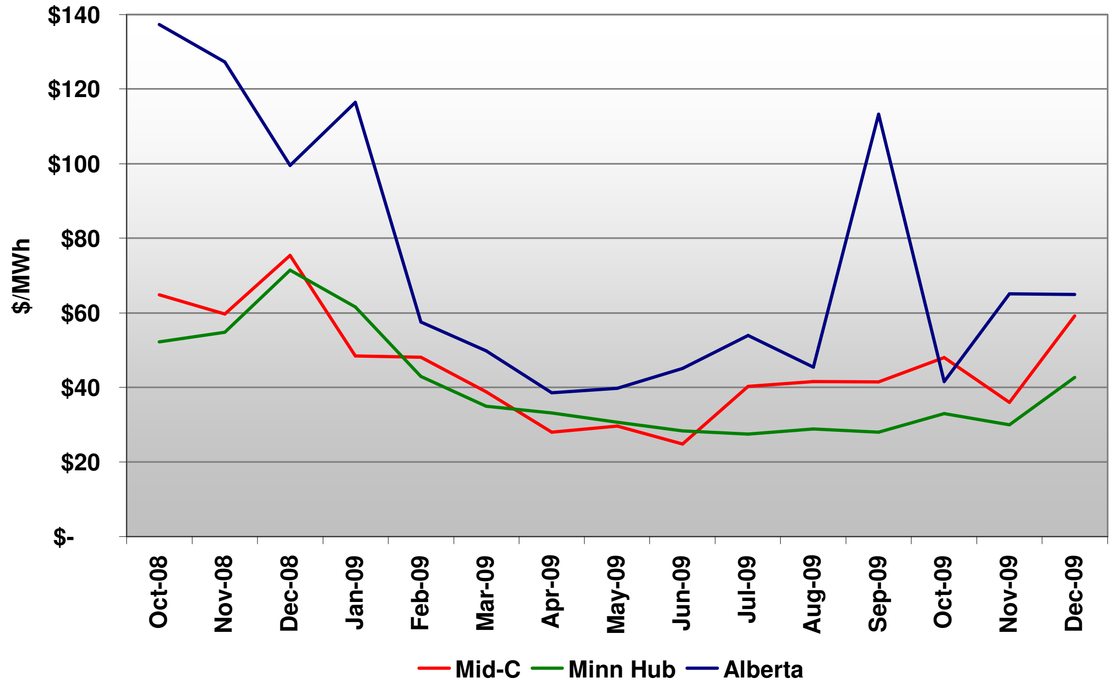


Figure 27 - Off-Peak Prices

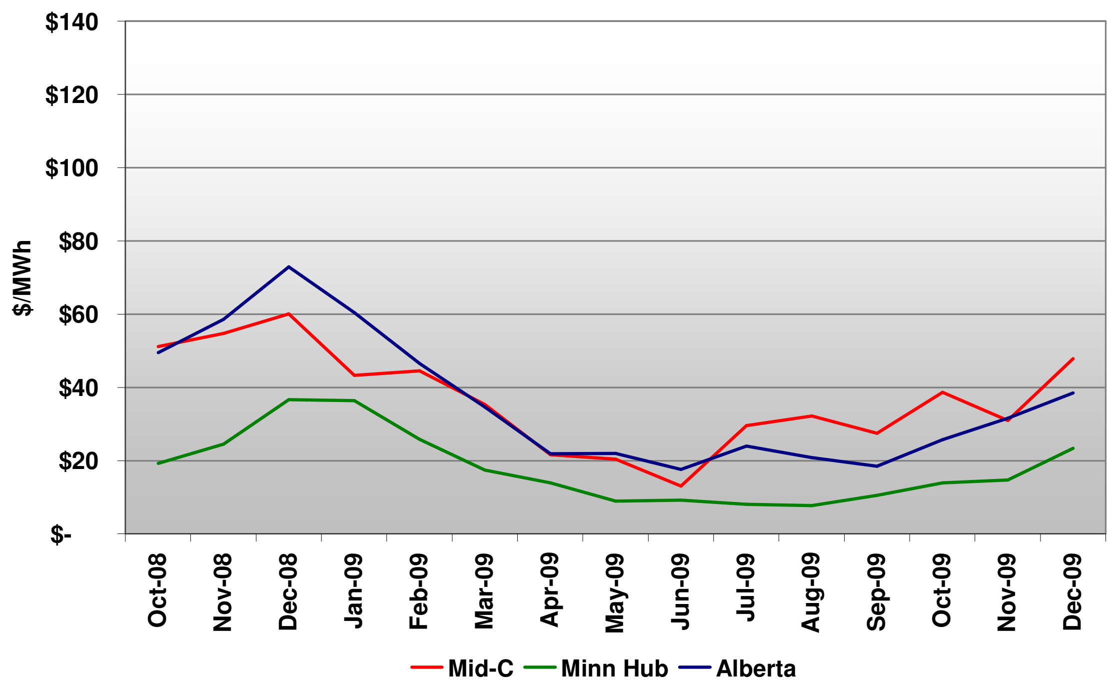


Figure 28 - BC Intertie Price Differential and Net Flow

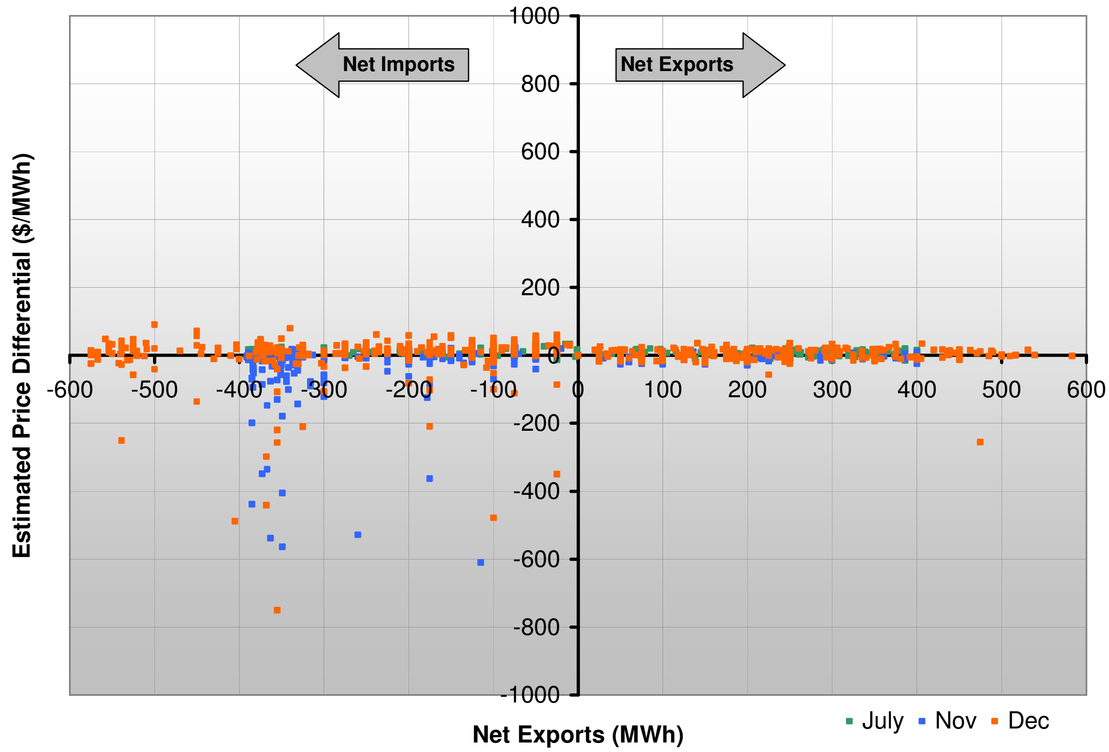


Figure 29 - SK Intertie Price Differential and Net Flow

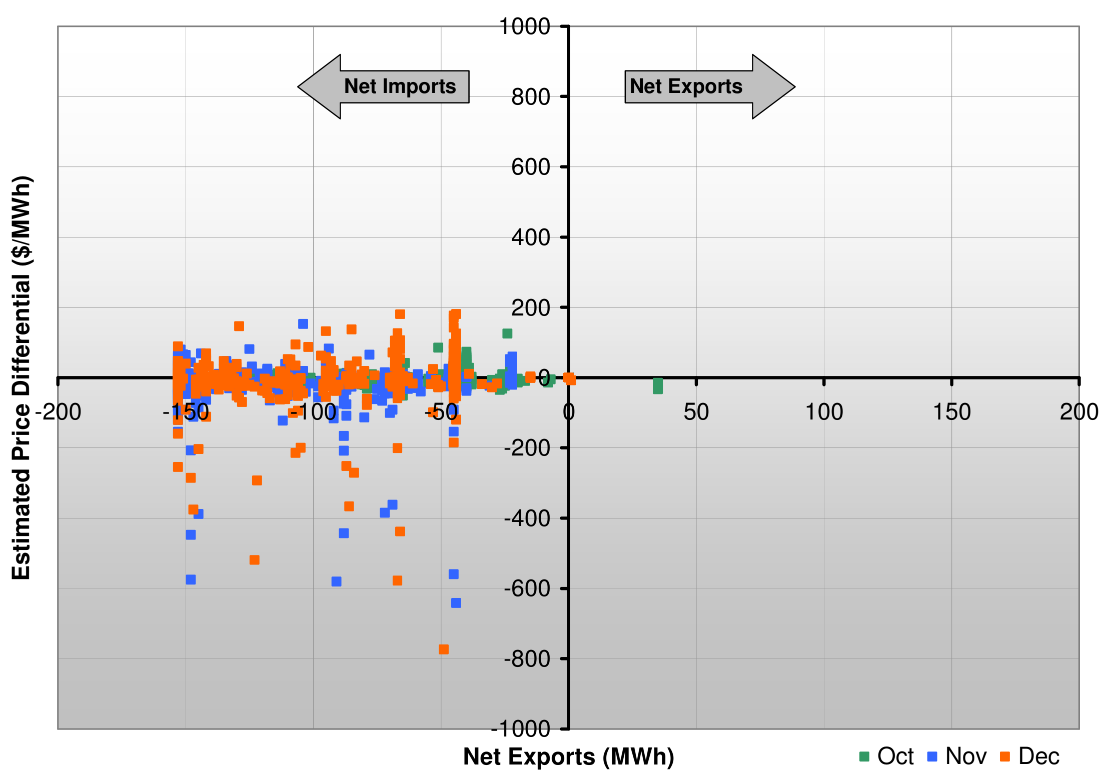
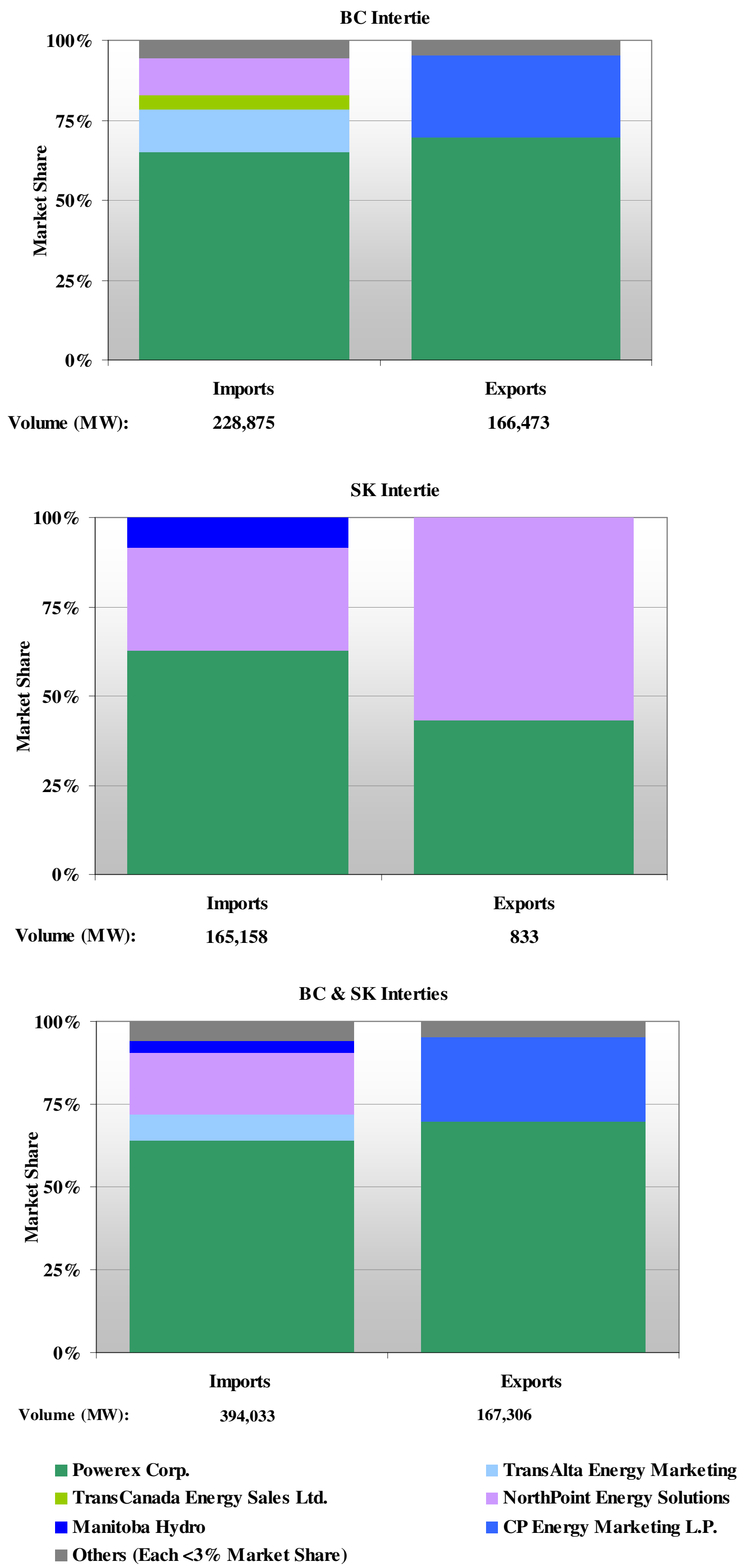


Figure 30 - Intertie Market Share



APPENDIX F – FORWARD MARKET METRICS

Figure 31 - Volume by Trading Month[10]

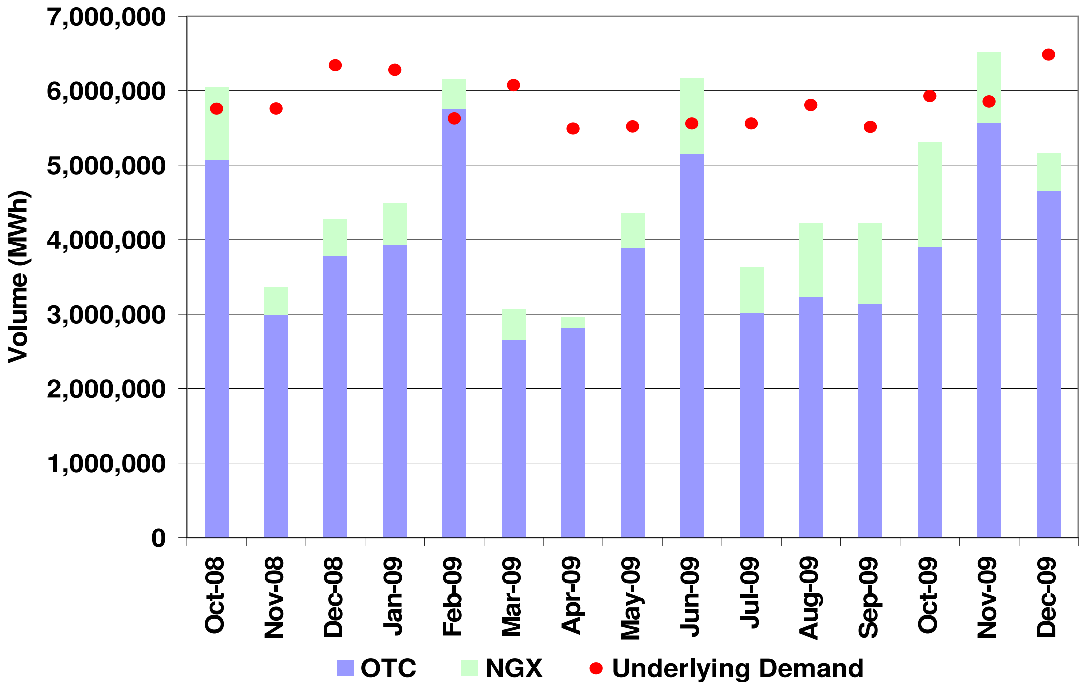
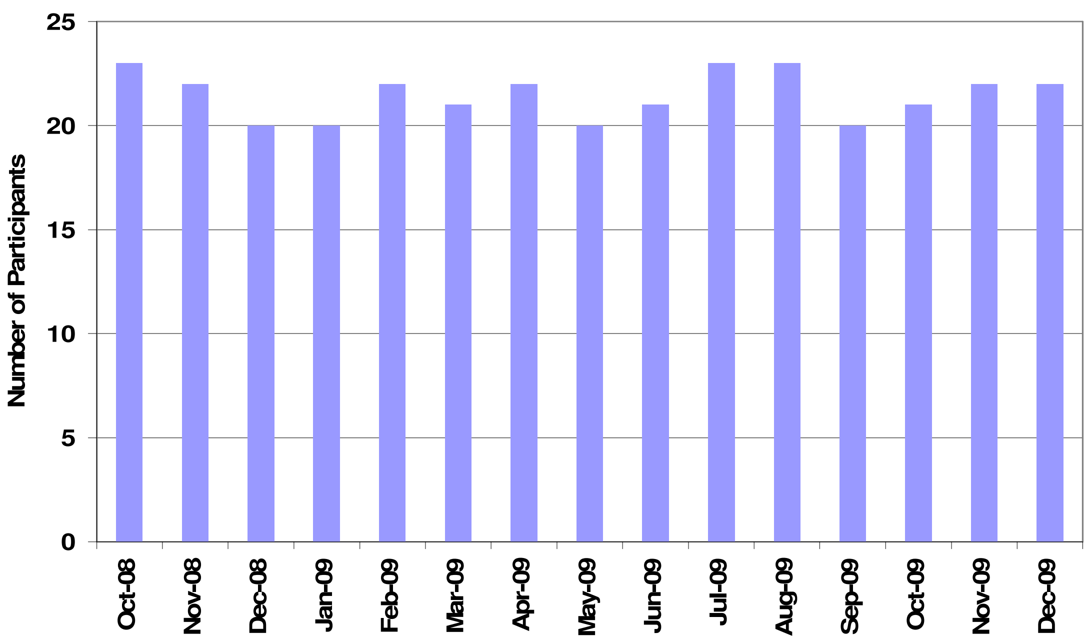


Figure 32 - Number of Participants by Trading Month



[10] The volumes include only one side of the transaction. NGX volumes do not include transactions not facilitated by but settled through NGX.