www.albertaMSA.ca

MSA REPORT

Quarterly Report

April - June, 2010

9 August, 2010

MARKET SURVEILLANCE ADMINISTRATOR

TABLE OF CONTENTS

PAGE

LIST OF FIGURES

LIST OF TABLES

1 EXECUTIVE SUMMARY

Wholesale Market: The Q2/10 average Pool price of $81.15/MWh and average natural gas price of $3.69/GJ yielded the highest market heat rate since 2000 at 22 GJ/MWh. Market tightness was especially evident in May which had an average Pool price of $134.69/MWh. Alberta Pool prices were higher than those of neighbouring markets and imports on the interties were high at 736 GWh. Export opportunities were very limited and total exports amounted to only 23 GWh (less than 3% of total imports).

A major contributing factor to the high May Pool prices was the amount of available generation that was constrained down due to transmission issues. The three main sources of constraints were unplanned transmission outages following a major snow storm in mid April, work in the Keephills-Ellerslie-Genesee area to facilitate the future interconnection of Keephills #3 unit, and wind generation curtailments due to excessive loading on transmission lines in the southwest of the province. In some hours the amount of supply constrained by these actions amounted to more than 1000 MW. The level of unit outages and derates was not high, but once combined with the amount of generation constrained down, the market was very tight and associated Pool prices were very high. Overall, the high prices of Q2/10 were driven by market fundamentals.

Rapid Changes to Monthly Outage Graph: There was an incident in May in which the AESO's Monthly Outage Graph went through two changes close together in time. This caused some concern in the trading community over the validity of the data included in the graph. The Monthly Outage Graph is a forward view of the total planned outages by fuel and is a guide to participants on the potential level of market tightness and is an important piece of market information. The MSA's enquiries and analysis revealed that the cause of the rapid changes was a human error of reporting outage information to the AESO. Correcting the error made it appear that two changes had occurred in close proximity of time. A more frequent cause of this kind of pattern is the handling of outage information for PPA units with their associated Owner and Buyer protocols. In this report, we propose that perhaps all changes to the Monthly Outage Graph should be made overnight when the forward market is closed. Market participants are invited to provide their views on this suggested process change.

High Stand-By Operating Reserve Prices: Prices for Operating Reserves typically follow the trend of Pool prices. When the Pool prices in May were high, the prices of the three active Operating Reserve products (regulating, spinning and supplemental) were also high. Similarly, the prices for the stand-by products were high in May. As the month of June evolved and Pool prices settled lower, so did the prices of the active reserves, but the stand-by reserve prices stayed quite high.

High stand-by prices for on- and off-peak regulating reserves recurred starting in late June and continuing until late July. In some weeks the average price paid for active on-peak regulating reserve was less than the average premium paid for the stand-by product, which appears counter intuitive. The MSA will continue to keep a watchful eye on this segment of the market.

Roundtable Discussions on Offer Behaviour Guideline: This important MSA initiative continued through Q2/10. Two papers were produced and the MSA has solicited feedback from market participants by the end of July, 2010. The MSA hopes to move through the stakeholder consultation process to develop a Guideline on offer behaviour by the end of 2010. Work is underway on the development of hypothetical examples to illustrate some of the finer points of the MSA's intended enforcement approach. The examples will be drafted with the aid of market participants and then discussed in a stakeholder workshop.

AUC Proceedings: The AUC issued several decisions in Q2/10 that have a bearing on the MSA and its activities

The MSA filed two settlement applications requesting confidentiality. In each case confidentiality was sought on the basis that the settlement brought to the AUC for approval reflected negotiations conducted on a 'without prejudice' basis, and that it would be in the public interest for the AUC to maintain confidentiality around critical content until its decision on the settlement was issued. The AUC was not convinced that this was warranted and denied the requests for confidentiality. The MSA will continue to explore the avenues available to it that are administratively efficient and promote a collaborative approach to compliance among market participants.

The Fair, Efficient and Open Competition Regulation (FEOC Regulation) requires participants to obtain AUC approval to share confidential information on price and quantity offers. The Power Purchase Arrangements (PPAs) are an important feature of the landscape of the Alberta electricity market. The AUC held a generic written proceeding to consider whether approval would be required for information sharing between PPA Owner and Buyer in relation to two types of PPA capacity, Increased Capacity and Excess Energy. The AUC decided that approval would not be required in those instances. The AUC separately issued a decision approving sharing of price and quantity offer information by the Balancing Pool pursuant to the Genesee PPA. Both decisions provide useful clarity for market participants and the MSA.

2 WHOLESALE MARKET

As indicated in the MSA's Q1/10 report, over time there will be changes to this report series and new tables and charts will be introduced with an increased emphasis on the measurement of competition. Where the changes are small and need no particular explanation, they will be included in the relevant appendix. In those cases where some explanation is needed to afford the reader the opportunity to fully absorb the information contained in the new metrics, they will be included at the front initially and generally integrated with the text. If you have any questions about these new metrics, please to do hesitate to contact Mike Nozdryn-Plotnicki (ph. 403-705-8503 or mike.nozdryn-plotnicki@albertamsa.ca).

2.1 Wholesale Market Fundamentals

Pool prices in Q2/10 averaged $81.15/MWh (see Table A1 in Appendix A), almost double that for Q1/10 ($40.78/MWh) and more than double the average for Q2/09 ($32.30/MWh). Most of this increase can be attributed to high prices in mid May that will be discussed in some detail below in Section 2.4.

Natural Gas prices were moderate throughout Q2/10, averaging $3.69/GJ (see Figure A2). This leads to an implied market heat rate for Q2/10 of 22 GJ/MWh (= $81.15/MWh / $3.69/GJ) – notably, this is the highest value since 2000.

Little new capacity was added to the system in Q2/10 with just 40 MW of addition to Nexen's Long Lake project. No retirements occurred in the quarter, although Wabamun #4 (272 MW) was retired by TransAlta on the last day of Q1/10. Coal plant availability (see Table B1 in Appendix B) in Q2/10 was lower than in Q1/10 by about 700 MW on average, due to plant maintenance and the absence of Wabamun #4. Average generation from the coal fleet was lower by about 850 MW, a greater drop than that in availability. At first glance, it might appear that the coal fleet was withholding more in Q2/10 than in Q1/10. As is discussed in Section 2.4, significant volumes of generation were constrained down in Q2/10, particularly in May, and much of that constrained generation was from the coal fleet.

The average demand in Q2/10 was 7785 MW, well down from Q1/10 (8410 MW) but up 2.6% from Q2/09 (7587 MW).

Figure 2-1 is a variant on one the MSA has shown in the past and that will be featured in future quarterly reports on a regular basis. Observation of the Alberta market for many years has indicated that market 'tightness' is a better price predictor than demand.

Figure 2-1 is comprised of three parts:

- Supply cushion duration curves for Q2/10, Q1/10 and Q2/09;

- Plot of Q2/10 supply cushion duration curve with concomitant Pool prices; and,
- Simple linear correlation of Pool price and supply cushion for the three noted quarters.

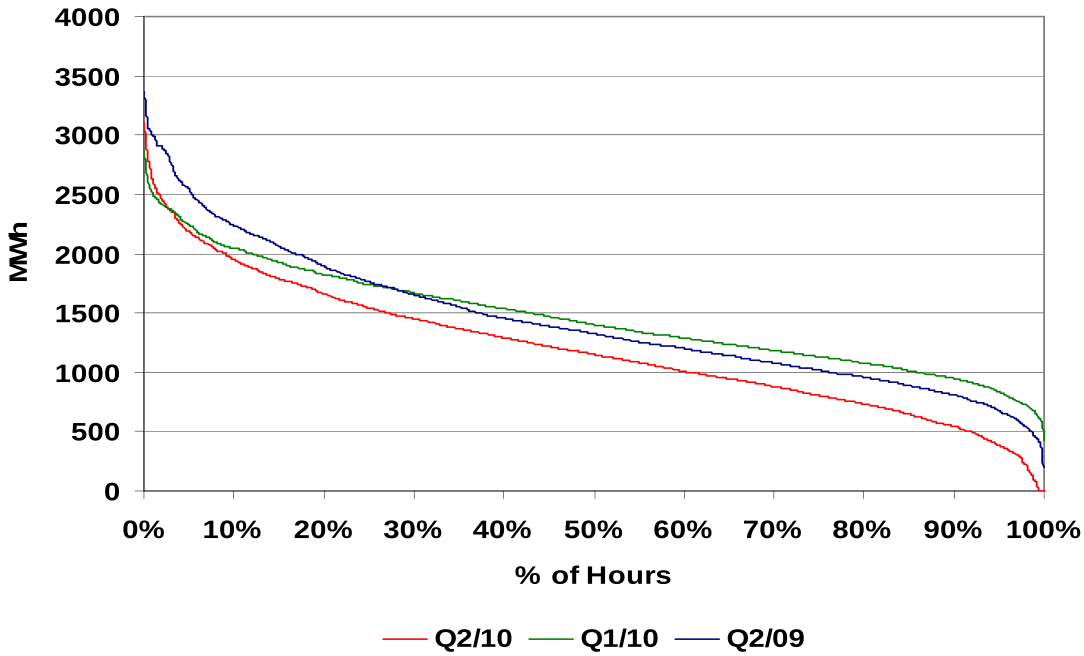
The supply cushion in any particular hour is the total undispatched energy offers in the merit order in that hour. It is estimated using a data snapshot close to the middle of the hour and occasionally (~1%) hours are missed due to data issues.

When considering the supply cushion values, it needs to be recognized that there are some limitations:

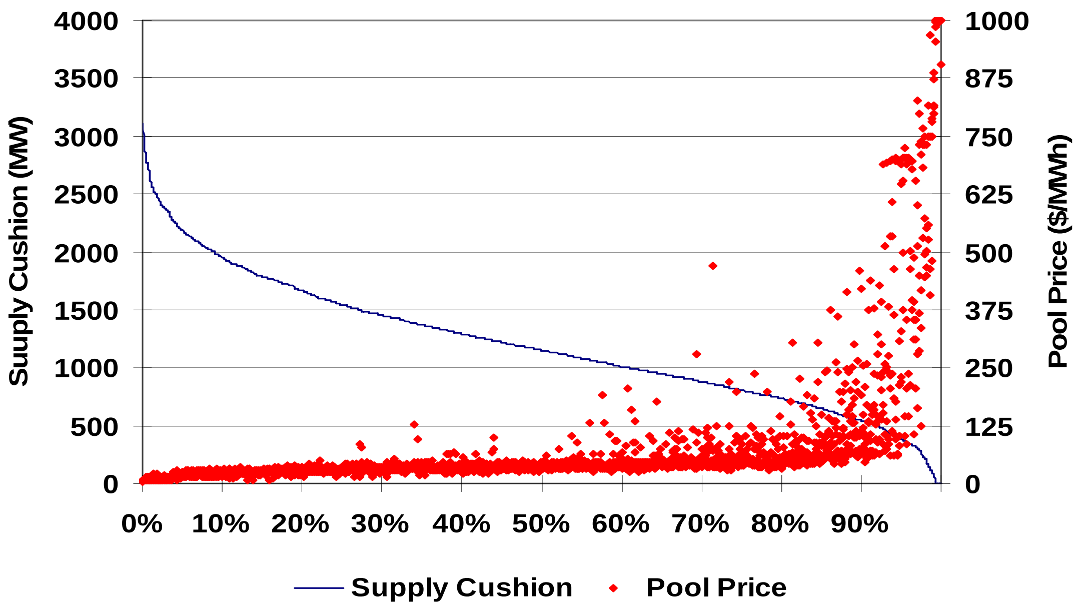
- In some hours, there is appreciable dispatching that occurs and a point value in mid hour may not be representative of the hour as a whole;
- Long lead time units may not be running although available – most of the capacity of those units is available in near future hours; and,
- Unused import capacity, whilst not available in the current hour, likely is available to flow in near future hours.

Figure 2-1 Analysis of Supply Cushion Data

Supply Cushion Duration Curves



Supply Cushion vs Pool Price Q2/10



Correlation between Supply Cushion and Pool Price

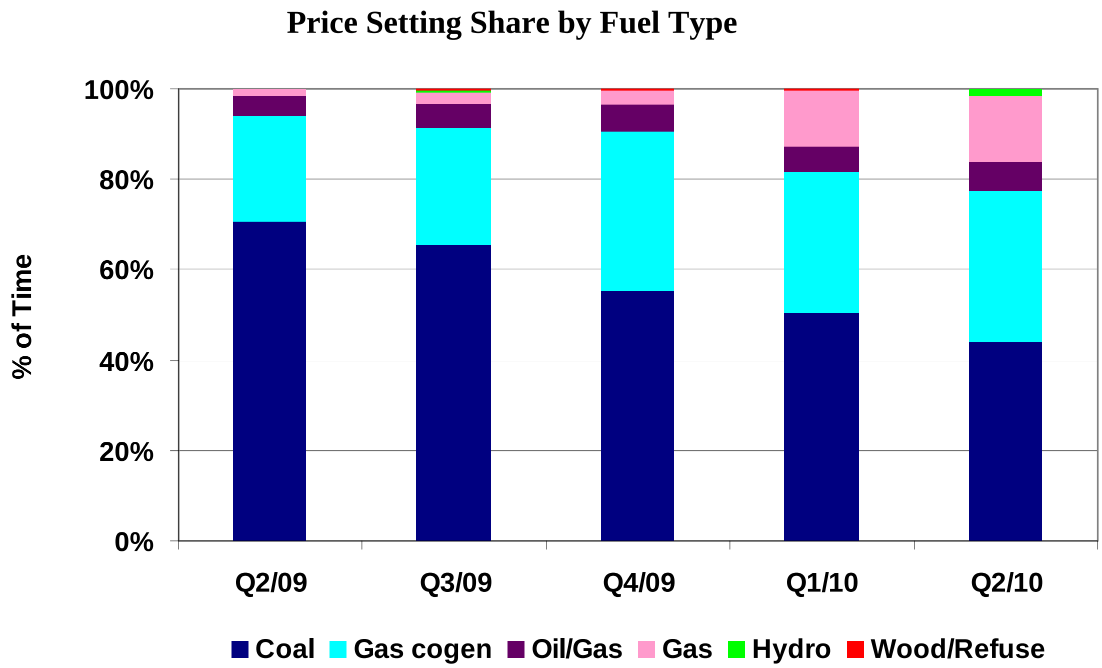
Q2/10	Q1/10	Q2/09
-54%	-64%	-44%

2.2 Price Setting Shares

Figure 2-2 shows the price setting share and average price level by fuel type and by quarter. It is apparent that price setting by the coal fleet has declined through the past five quarters, and largely replaced by gas plant (Gas Cogen and Gas).

For the fuels that set the System Marginal Price most frequently, Figure 2-2 shows the expected pattern of average price levels within each quarter. From lowest to highest average price the order is coal, gas cogen, gas and then hydro. The actual price levels vary significantly across the quarters, due in part to changing natural gas prices and in part to market tightness.

Figure 2-2 Price Setting and Average System Marginal Price Level by Fuel and by Quarter



Average System Marginal Price by Fuel Type

Fuel Type	Q2/09	Q3/09	Q4/09	Q1/10	Q2/10
Coal	27.20	32.93	37.61	33.18	36.18
Gas	86.09	182.06	151.95	55.34	150.93
Gas cogen	41.15	63.47	48.96	45.40	89.94
Hydro	643.63	198.44	288.10	283.18	198.58
Oil/Gas	39.66	100.27	49.21	46.56	151.60
Wood/Refuse	NA	160.57	69.15	25.00	843.72

2.3 Imports and Exports

High Alberta Pool prices in Q2/10 relative to neighbouring markets attracted significant volumes of imports. Figures E2 and E3 in Appendix E clearly illustrate the significant import opportunity that existed. The total volume of imports in Q2/10 was some 735,800 MWh, equivalent to an average 337

MWh over the whole quarter. Exports on the other hand were nominal at 22,700 MWh.

In continuing to monitor and report on Alberta intertie utilization and efficiency, the MSA has developed a new view of intertie performance, building on the other graphs presented in Appendix E.

Figure 2-3 and 2-4 are variants of a histogram, depicting the Q2/10 cumulative flow of energy and cumulative Available Transfer Capacity at varying levels of estimated price differentials (net of transmission costs) between Alberta and neighbouring markets.

The vertical axis plots the sum of the hourly flow, and sum of unused Available Transfer Capacity (ATC) in each of the hours with associated price differential ‘bins’ on the horizontal axis. Negative values correspond to imports and positive to exports. The price differentials include allowances for transmission costs and thus indicate estimates of potential profit. The calculation of unused Available Transfer Capacity in an hour considers the net scheduled flow and the import and export Available Transfer Capacity limits. As an example, if the net schedule in an hour is -100 MW, import Available Transfer Capacity is -200 MW, and export Available Transfer Capacity is 50 MW, the unused import Available Transfer Capacity (= ATC – net schedule) will be equal to -100 MW (= -200 – [-100]), and unused export Available Transfer Capacity will equal 150 MW (= 50 – [-100]). Positive price differentials indicate that the intertie transaction was profitable in the hour (on an imputed basis).

The expectation is that profitable opportunities will be seized and, subject to the ability to flow energy, the amount of un-seized opportunities will generally diminish with increasing potential profits. The converse should also be true - unprofitable opportunities should increasingly be avoided as the potential losses increase.

The results for Q2/10 generally conform to expectations, with some exceptions. Profitable import opportunities are generally well subscribed, and unprofitable export opportunities are largely avoided.

This type of presentation does not capture the time distribution of events. In Section 2.4.2 we discuss unrealized profitable hours in May when Pool prices were persistently high and foreseeable. At such times interties flowing less than full are not a positive sign.

Figure 2-3 BC Intertie Flows in Q2/10, Imputed Profitability and Unused Capacity

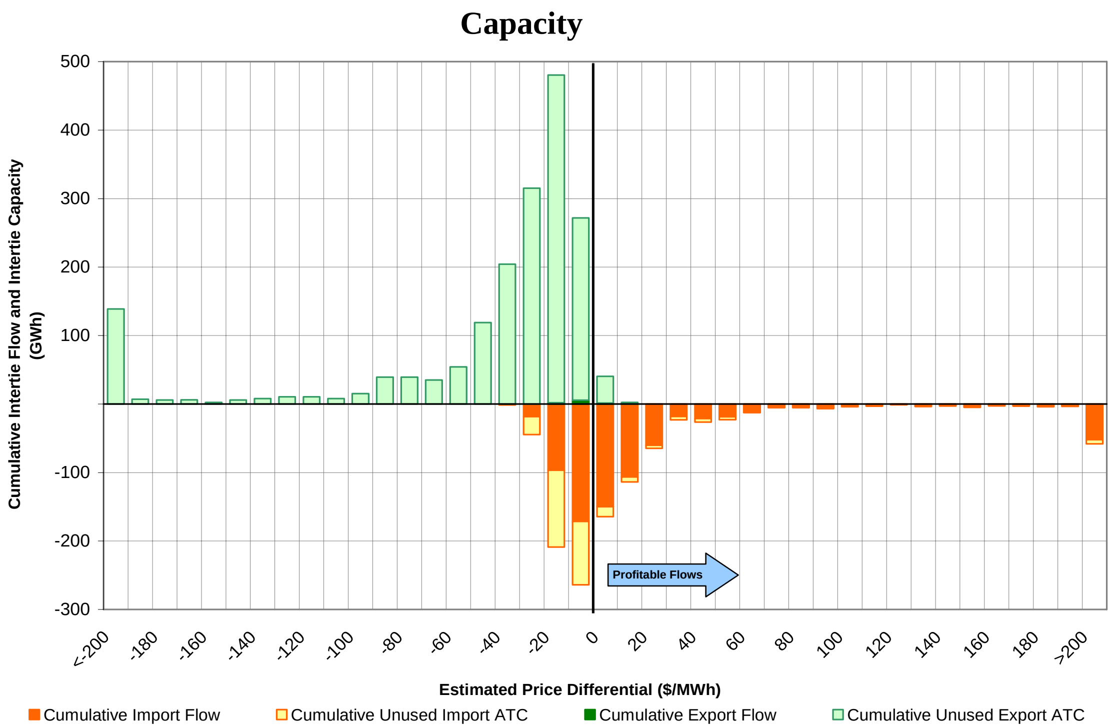
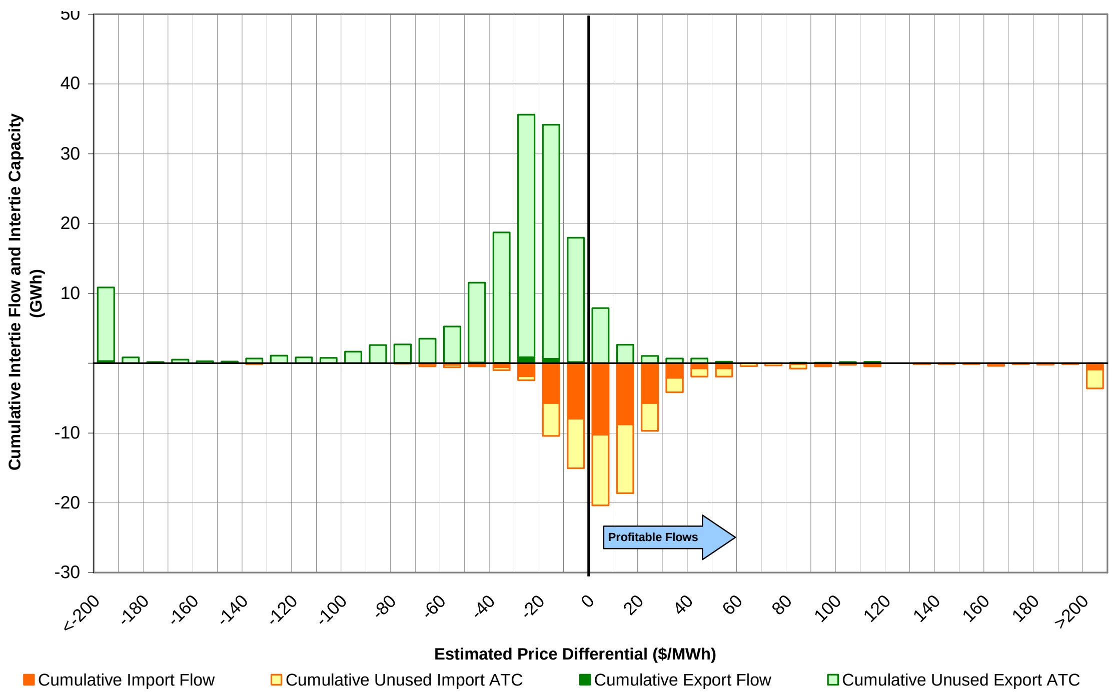


Figure 2-4 SK Intertie Flows in Q2/10, Imputed Profitability and Unused Capacity



The figures also show that exports occurred more frequently at a loss, than at a profit, with small volumes with imputed losses as great as $40/MWh. It needs to be recognized that in Q2/10 the volume of exports was only 22,700 MWh, less than 3% of the total exports (735,800 MWh).

2.4 May Price Events

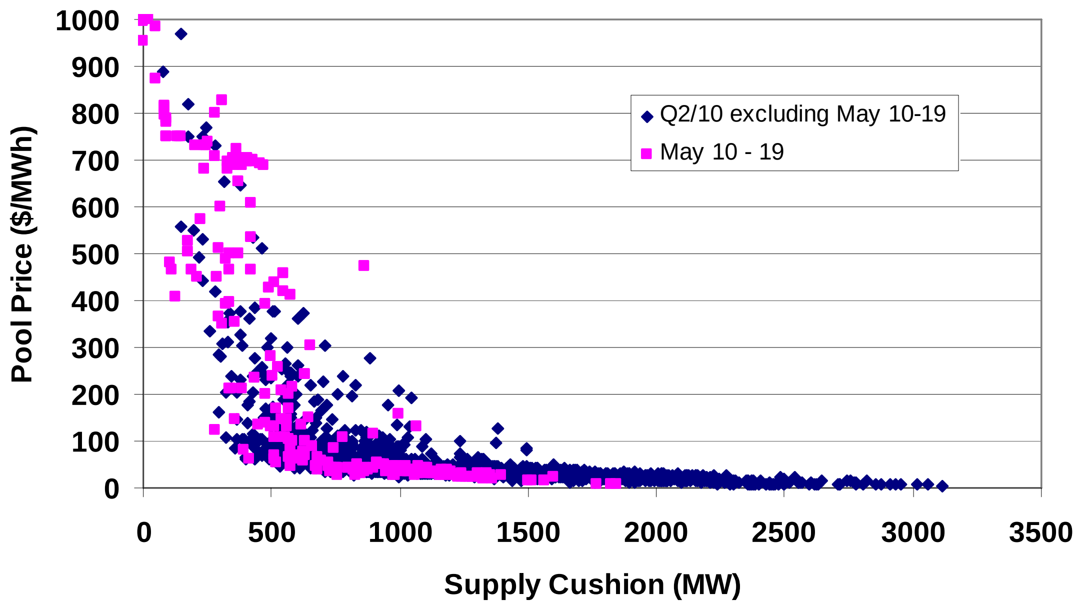
May 2010 experienced energy market prices significantly higher than any other time to date in 2010. From May 10th through May 19th, average Pool price was almost $300/MWh, whilst the balance of the month was moderate, averaging about $56/MWh. On-peak Pool prices in the May 10th to 19th period were regularly around $700/MWh for several contiguous hours. Table 2-1 presents the daily, on-peak, and off-peak average Pool prices for the three months of Q2/10, and also breaks out the May 10th to 19th period.

Table 2-1 Monthly Average Prices for Q2/10

	All Hours	On-Peak	Off-Peak
April	$ 49.71	$ 61.51	$ 33.57
May	$ 134.69	$ 193.55	$ 60.03
May 10 - 19th	*$ 299.48*	*$ 418.34*	*$ 121.19*
June	$ 57.27	$ 79.44	$ 26.93

To further highlight the market price outcomes of May 10th – 19th against the rest of the quarter, Figure 2-5 plots hourly Pool prices for Q2/10 and associated supply cushions. The values associated with the May 10th to 19th period clearly form a major portion of the hours of low supply cushion and high Pool price.

Figure 2-5 Q2/10 Hourly Supply Cushion and Pool Price



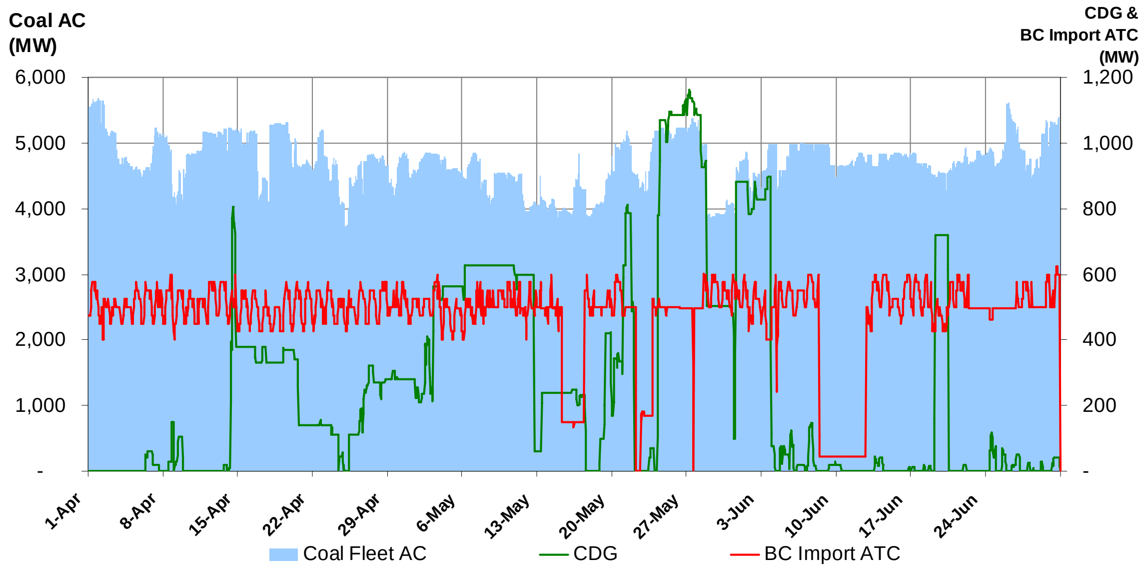
The most extreme cases of market tightness occurred on May17th and 18th, where an Energy Emergency Alert Level 1 was declared 3 times: twice on May 17th for a total of approximately 5 hours, and again on May 18th, for approximately 5 hours. Energy Emergency Alerts occur once the System Controller has exhausted the energy merit order.

Several factors contributed to the Energy Emergency Alerts. AIES system load was high on May 17th and 18th, peaking between 8600 and 8700 MW, as compared with demand peaks around 8100 MW in the prior week.

Supply scarcity was also a contributing factor. As many as 5 coal units were offline on May 17th, resulting in only 3800 MW of available coal capacity (or about 65% of total coal capacity). Leading up to and during the first Energy Emergency Alert declaration, there was some constrained down generation, and transmission line work that limited imports across the BC intertie. Finally, wind generation was low through most of the supply shortfall hours.

Figure 2-6 plots Coal Fleet Available Capacity, Constrained Down Generation (CDG), and BC Import Available Transfer Capacity (ATC) on an hourly basis for the quarter.

Figure 2-6 Coal Available Capacity, Constrained Down Generation, and BC Import Available Transfer Capacity



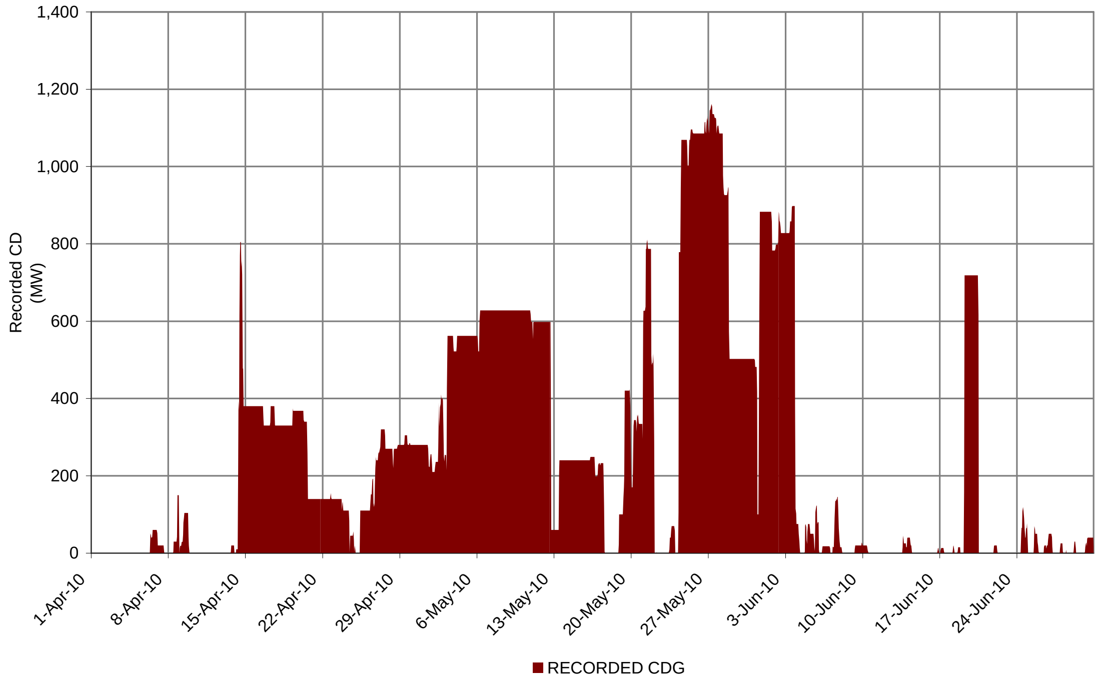
The MSA observed that supply scarcity was a driving factor through most of the high priced hours in the May 10th to 19th period. Similar factors contributed to the formation of high prices during the broader period in May, including high levels of constrained down generation, limited import Available Transfer Capacity and/or underutilized import capacity, and generator offer behavior. Overall, the main driver was scarcity due to the combined effects of unit outages and the unusual amount of generation that had to be constrained down.

2.4.1 Constrained Down Generation

Constrained down generation (CDG) occurs when a generator's output is limited to maintain the reliable operation of the transmission system receiving the energy. Constrained down generation results in a direct reduction in supply to the energy market, and also impacts the Dispatch Down Service (DDS) market, by reducing the amount of DDS procured.

Figure 2-7 presents the recorded Alberta Interconnected Electric System constrained down generation for Q2/10. Constrained down generation was particularly prevalent in the second half of April, and through most of May, with total constrained down volume at times exceeding 1000 MW.

Figure 2-7 AESO Recorded Constrained Down Generation



The MSA has conducted an analysis of constrained down generation in Q2/10, based on the AESO's recorded constrained down generation values and the AESO System Controller logs. The constrained down generation value recorded by the AESO does not identify the source of the constraint, so the MSA utilized the System Controller logs to estimate the amount of constrained down generation due to each of the types of constraints in each hour of the quarter.

The study determined that there were three significant causes of constrained down generation in Q2/10:

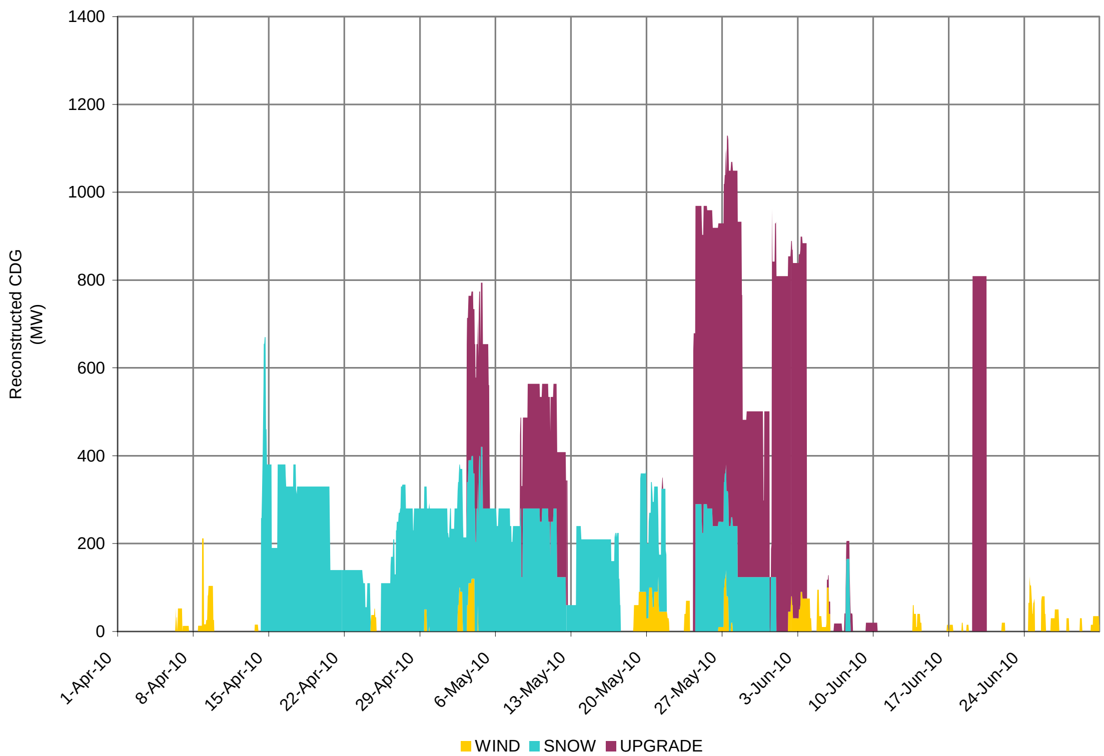
- Wind Generation Curtailments were required at some wind facilities during times of heavy transmission line loading in the Southwest of the province. These constraints were sporadic, but typically occurred during periods of high wind generation.
- Unplanned transmission outages occurred when a spring storm on April 14th severely damaged a number of transmission towers in the Hanna region creating constraints for the Battle River and Sheerness generating stations. The affected lines were restored by early June and no further constraints were imposed on these generators[1].

[1] The AESO provided an update on repairs related to the storm on the 14th of April in a report available on their website: http://www.aeso.ca/downloads/Southeastern_Alberta_storm_recovery_procedures_April_30_2010_final.pdf

- Planned transmission upgrades in the Keephills-Ellerslie-Genesee (KEG) area related to the Keephills #3 interconnection upgrades limited the KEG cut-plane, and south of KEG flow, constraining the Genesee and existing Keephills units. These upgrades began in early May and are expected to continue into October 2011[2].

Constrained down generation attributable to each source is presented on an hourly basis in Figure 2-8. In some hours the MSA was not able to completely reconcile the logged value of constrained down generation with the recorded total value, although this only affected a small portion of the total number of hours.

Figure 2-8 Constrained Down Generation by Source



Differences between the recorded value, and reconstructed value could be the result of several factors:

- This analysis was on an hourly basis, although constrained down generation can vary within the hour.
- The variability of wind generation causes the process of estimating the amount of power that would have been produced absent the constraint to be challenging and inherently imprecise. A proxy might be the maximum capacity of the wind facility, or the level at which the

[2] Information about the Keephills 3 Interconnection Project can be found at: http://www.aeso.ca/transmission/20222.html

wind farm was producing immediately before the constraint was declared. The MSA found what appeared to be a mix of both approaches to record the constrained down generation value of wind. Going forward, the availability of facility specific meteorological data should enable a more accurate and precise estimate of the potential MW at a constrained down facility.

- When a generator restates its Available Capacity value below the level of the transmission constraint, the transmission constraint no longer is a constraint. The MSA found several instances where generators restated Available Capacity below the level at which the constraint had an effect but the constrained down generation value did not appear to be updated.
- Given that the recording of constrained down generation components was a fairly manual process, human error cannot be discounted.

The MSA also observed many instances where out of merit offers were constrained down. Appropriately, the AESO's recorded value of constrained down generation does not include out of merit MW in the total.

Constrained down generation is also incorporated into the AESO's Short Term Adequacy[3] metric. During high priced periods when planned transmission upgrades were a significant cause of constrained down generation, the MSA observed that the Short Term Adequacy metric did not appear to reflect anticipated changes to constrained down generation on a forward looking basis. That is, the level of constrained down generation in the current hour appeared to be assumed constant going forward, even when there was a known end to the constraint in the near future. This resulted in the Short Term Adequacy forecast of future hours shifting dramatically as changes to the current hour constrained down generation value occurred.

The MSA believes this forward looking information about supply scarcity could be compromised; particularly at times when constrained down generation is a major contributor to the scarcity. The Short Term Adequacy report is meant to provide a signal to both suppliers and consumers of the level of tightness in the market over the next several days. This information assists them to make more efficient production and consumption decisions. On those occasions when the amount of generation constrained down is significant, it becomes important to reflect this as accurately as possible in the report. If the AESO foresees any future occasions wherein the level of constraints approaches that observed in May it would be worthwhile to invest the resources to improve the Short Term Adequacy report to include a forward view on constraints.

[3] The Short-Term Adequacy Metric is a real-time AESO report that may be viewed at: http://ets.aeso.ca/ets_web/ip/Market/Reports/SupplyAdequacyReportServlet

2.4.2 BC Intertie Availability and Utilization in May

The plot of the BC intertie Available Transfer Capacity through Q2/10, presented in Figure 2-6, shows a significant lessening of Available Transfer Capacity through a portion of the high priced period in May. Like some of the constrained down generation, this was the result of planned transmission work for the Keephills #3 interconnection upgrade.

The MSA also observed hours in May where import Available Transfer Capacity on the BC intertie was not fully utilized when high Pool Prices made imports from Mid-C highly profitable[4]. When imports have a potential profitability of >$300/MWh and are reasonably foreseeable, the expectation is that the interties will flow to the maximum extent. In such situations, even 100 MW of unused capacity appears to be inefficient. Over the whole of Q2/10, there were 19 hours when the BC intertie had more than 100 MW of unused capacity foregoing a profitable opportunity of more than $300/MWh. Eleven of the 19 occurrences were in the May 10th to 19th period. The remaining 8 occurrences were scattered over the balance of Q2/10.

Analysis revealed that in almost all of those hours the ‘Northern intertie’, the intertie between BC and the Pacific North West was very close to being congested. In turn, this appeared to be a consequence of high volume of BC-bound flows. In such cases, importers found it difficult to access the Alberta market from the Pacific North West on the unused portion of the BC to Alberta intertie.

For many years, some market participants have raised a concern about the ability of some companies to purchase firm transmission rights that give them an ‘unfair advantage’ in transacting with Alberta over the interties. The Alberta market does not follow a transmission rights-based model. The MSA is looking at the circumstances leading to the congestion on the Northern intertie to understand the issues more fully.

Looking to the near future, the Montana Alberta Transmission Line is slated to begin construction very soon. There is no additional import capacity when this line is constructed (at least not in the first few years) and the AESO Market Services team is wrestling with the issue of how to allocate intertie access to the Alberta market among participants who have transmission rights outside Alberta, but where none of those rights apply here in Alberta. The MSA’s perspective on this matter remains that the interties should help the Alberta market to operate in a more efficient fashion. When Alberta Pool prices are sufficiently high, imports should flow to the maximum extent possible – until the ‘arb’ is closed and no profit remains. The same rational applies to the consideration of exports.

[4] The Saskatchewan intertie was derated to 0 MW import capability during most of May and was not a factor.

2.4.3 Offer Behaviour

The MSA monitors the electricity market to ensure that it operates in a fair, efficient and openly competitive manner. The MSA is currently working with stakeholders to develop a guideline that will provide a framework for this monitoring and assessment. The proposed approach accepts that some short-term inefficiency is going to occur from time to time, and indeed may be essential to the viability of an energy-only market such as the one in Alberta. However, the approach also relies on the presence of effective competition in the market, particularly supplier-on-supplier competition. This section speaks to observations of offers to the market in the high-price period of May, 2010.

Figure 2-9 shows the relationship between supply cushion, unused import ATC and Pool price over the period of May 13th to 15th and the discussion will now focus on this period.

Between May 13th and 15th, the MSA observed on-peak energy market prices at or near $700/MWh in several contiguous hours. Specifically of interest were the following hours:

- May 13th HE[5] 14 – HE 18
- May 14th HE 12 – HE 18
- May 15th HE 12 – HE 20

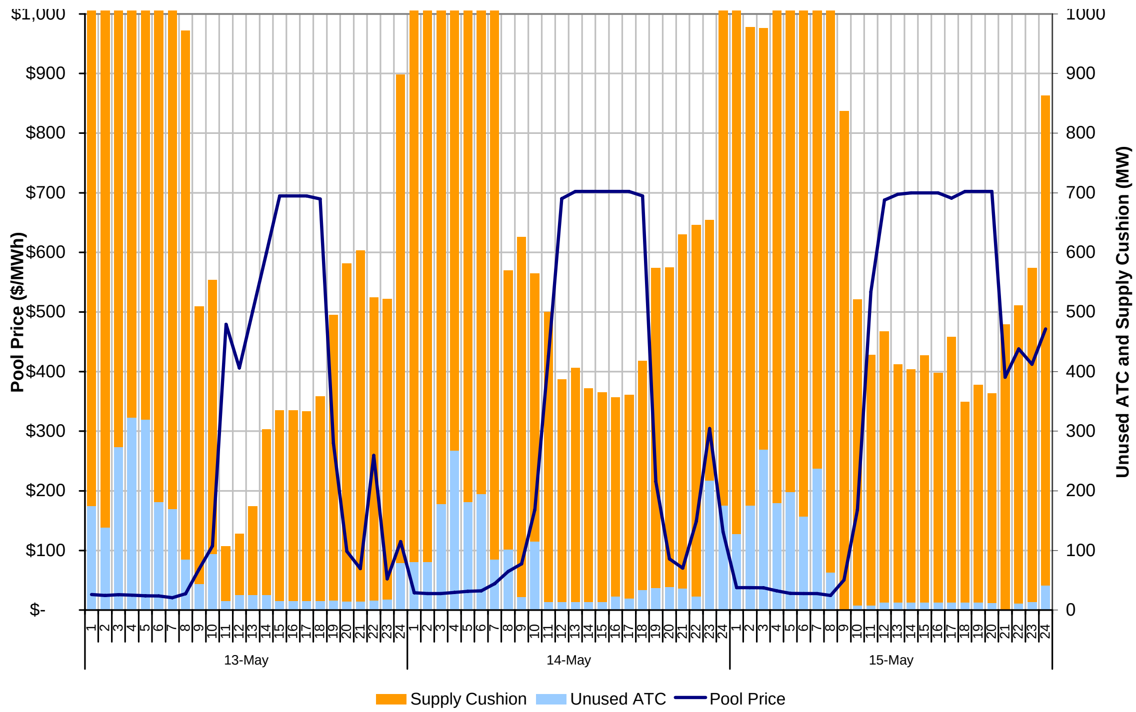
In all the above-noted hours, price was established by a combination of unit offers totaling about 170 MW from a single portfolio.

This offer strategy of the portfolio was adopted in HE 14 on May 13th, when four units which had been offered to the market between ~$40/MWh and $80/MWh were re-priced to approximately $700/MWh. The effect on System Marginal Price occurred about halfway through HE 14 as System Marginal Price increased from $464.71/MWh to $694.83/MWh and persisted at close to $700/MWh until early in HE 19. A similar and consistent offer strategy was employed in the on-peak hours for the following two days, and the portfolio's units established System Marginal Price almost continuously through the hours of interest.

Offering generation at these prices is not without risk. Participants take on dispatch risk which results in lower volumes of energy sales, but sales at higher prices. The offer strategy pursued by this portfolio had an effect on System Marginal Price, and thus Pool price, and was likely profitable given that the strategy was executed three days in a row.

[5] In the Alberta Pool, HE XX refers to the 60 minutes completed by the digits that follow. For example, HE 15 means the hour ending 3 pm.

Figure 2-9 Supply Cushion, Unused Import ATC and Pool Price - May 13-15, 2010



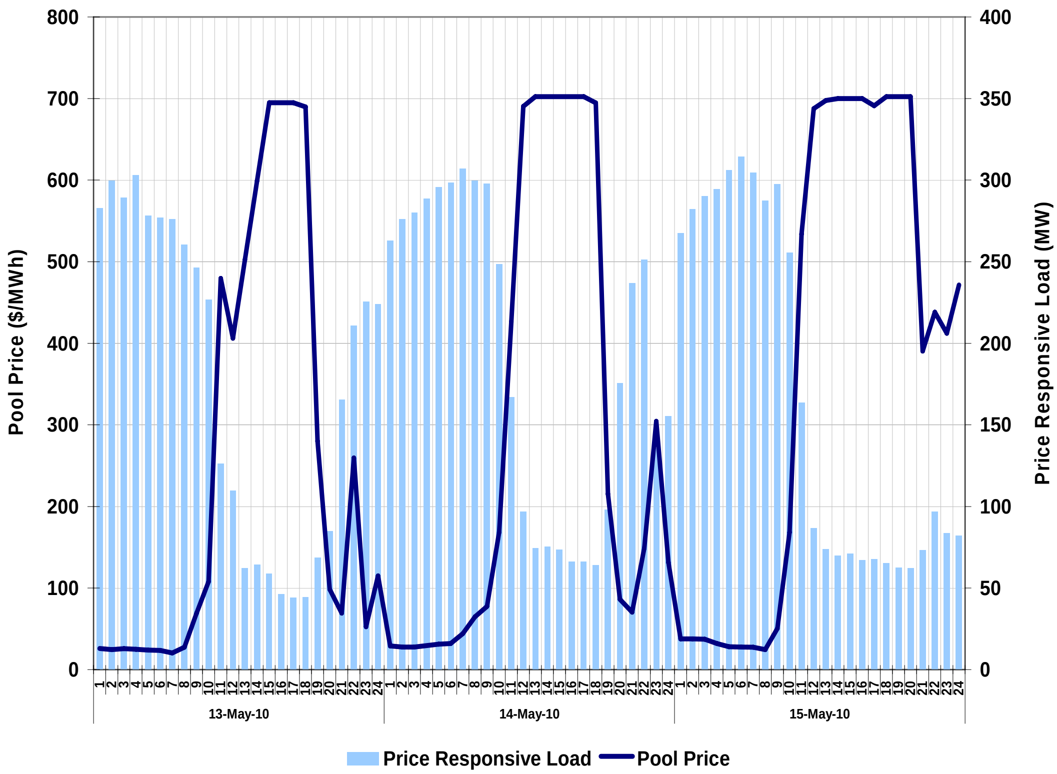
Throughout these hours the unused import ATC was very small, as indicated in Figure 2-9. Hence, the interties were unable to respond further to the high Pool prices.

Examination of the consumption for known price-responsive loads confirmed that around 200 to 250 MW of load reduction occurred on these three days seeming to respond as Pool prices ramped up over $100/MWh to $200/MWh (See Figure 2-10). As these price levels were surpassed earlier in the day, no additional response from load occurred as price increased to ~$700/MWh.

The market response that was still feasible was from the undispatched part of the merit order.

The MSA notes that the competitive response by the out of merit generators during the hours of interest was weak, given that the market observed the high price being set by a single, or tightly bound set of System Marginal Prices for as many as eight contiguous hours.

Figure 2-10 Price Responsive Load for May 13-15, 2010



The total of un-dispatched energy in the merit order during the hours of interest averaged approximately 385 MW (see Figure 2-9). With this level of market tightness, several market participants were pivotal. A market participant is defined as being pivotal if at least some of that participant's assets are needed to meet demand. The supply cushion was comprised of a variety of types of assets. The operating costs of these assets are unknown to the MSA. However it seems likely that some portion of the un-dispatched energy in the merit order could have been economically provided at the $700/MWh prices.

The MSA acknowledges that there are reasons that may explain why the un-dispatched units did not restate prices in an attempt to maximize dispatch in the face of persistent high prices. The opportunity cost of fuel, risk of incurred start-up cost with a short run time, or lack of awareness of market conditions could offer an explanation as to why some units did not restate. In some cases, the offered energy is available only by running the assets beyond normal maximum levels and the offered energy prices may reflect anticipated increased maintenance costs.

A significant portion of the un-dispatched assets in the merit order were held in two portfolios. One of them was the portfolio establishing price and not incented to under-cut itself. The MSA did observe some re-pricing of un-dispatched energy into merit from the second portfolio, apparently responding to the high Pool price. The re-priced volume was small and did not affect dispatch, meaning that the effect was absorbed by a combination of change in demand and the System Controller's regulating range. This was the only directly observed market response by the un-dispatched generators.

The days immediately following were even tighter in the on-peak hours with attendant high Pool prices. The above discussion on offer behaviour became less relevant since the market dynamics changed. By May 20, the tightness of the market dissipated and a new set of market dynamics began to manifest itself. This was caused by the return to service of some of the coal units that were on outage and an easing of the amount of constrained down generation.

For the period May 13th to 15th, a participant established System Marginal Price with part of its portfolio of assets. In the affected period, we have looked at the main sources of competitive response:

- Import capability was nearly fully utilized and not capable of additional response;
- Price-responsive load in the amount of 200 to 250 MW had occurred earlier in the days in question and showed no additional response when price levels reached the ~$700/MWh level; and,
- Supplier-on-supplier competition was observed but the volumes re-priced were small such that dispatch appeared to be unaffected.

Overall, this may be considered a somewhat muted response by the (available but not dispatched) market to the high prices observed in this occasion. In other instances, the MSA has observed fairly consistent offer behaviour from units held in small portfolios that take advantage of high Pool prices – whether created by scarcity as may result from forced outages or for other reasons such as withholding strategies. Understanding impediments to response in these and similar circumstances is an area of market monitoring that the MSA intends to spend more resources upon in the future.

3 FORWARD MARKET

Forward market volumes in Q2/10 at 83% of the physical spot market were higher than Q1/10 (75%) and about the same as Q2/09 (81%). The number of market participants in the forward market has remained quite stable in the low 20's for any particular month. There does not appear to be any obvious trend in the trading volumes or number of participants.

3.1 Incident in the Forward Market Involving the AESO's Monthly Outage Graph

The liquidity in the forward market is heavily influenced by market news that causes traders to change their market views and hence a need to adjust their positions through trading. In Q2/10 there was an incident involving one of the sources of market information used by traders. The source was the AESO's Monthly Outage Graph that provides some insights into upcoming generating unit outages. The incident involved some rapid changes to the Monthly Outage Graph that caused some concerns in the trading community.

3.1.1 The Importance of Monthly Outage Graph

One of features of the Alberta Market is that the Pool price is often very sensitive to the amount of outages at the base load coal-fired units. The changes in Pool price in turn have impacts on the profitability of participants' physical or financial positions that are exposed to the spot market prices. The forward market is a place where participants manage their expected price exposures in the spot market. The forward prices reflect market views about future supply and demand. The information about outages planned for future months, as indicated by the Monthly Outage Graph, helps participants to make better predictions of the spot market prices so that they can more effectively manage the risks of their positions. For many market participants, especially those with no physical assets, the Monthly Outage Graph is an important source of information. For this reason, the MSA is of the view that parties involved in the dissemination of outage information should make their best efforts to ensure that the Monthly Outage Graph reflects the outage plans as accurately as possible.

It must be borne in mind that the Monthly Outage Graph shows information on only the planned outages of future months. It cannot show unplanned outages (by definition) and these can often be significant. Further, the Alberta market model does not have centralized maintenance planning for generators and market participants make their own decisions. Revisions to outage plans are thus generally to be expected, as plant operators may have to reschedule outages for a host of possible reasons including labour shortages or delays in shipment of parts. Similarly, if it appears that many planned outages are simultaneous (from observation of the Monthly Outage Graph) the market model allows for participants to react and those with sufficient flexibility will adjust their own maintenance schedule accordingly.

Also, the Monthly Outage Graph includes elements of disguise to protect the interests of affected generators. This disguise, generally through aggregation and normalization of plants of differing fuel types, masks the exact amount of MW offline and the time period of the outages.[6]

3.1.2 Rapid Changes of AESO's Monthly Outage Graph

Around 4:45 pm on May 5, 2010, the AESO's Monthly Outage Graph showed a significant change in planned outages of the coal-fired generating units for July, August and September, 2010. The Monthly Outage Graph indicated a decrease in the coal-fired unit outages in July, and an increase in August and September.

[6] For details, refer to "Monthly Outage" help at http://ets.aeso.ca/.

This update in the Monthly Outage Graph did not have any immediate impact on the forward market since it was closed for the day. However, in the morning of May 6, traders who became aware of the updates in the graph reacted to the changes. Some of them entered into transactions based on the updated information given in the Monthly Outage Graph and adjusted their financial positions of the months that are expected to be impacted by the changes in coal unit outages. At round 8:50 am, the Monthly Outage Graph changed again, largely undoing the changes to the months of July and September.

These changes confused some of the market participants as outage plans are not expected to change as frequently as indicated in the rapid changes to the Monthly Outage Graph. Some participants expressed concerns about the credibility of the Monthly Outage Graph and the potential breach of Section 4 of the FEOC Regulation. Section 4 of FEOC Regulation restricts participants from trading on outage records that are not available to the public.

The Monthly Outage Graph and the associated Short-Term Outage Graph are constructed using data from market participants on the current and future physical availability of the assets they control. Available Capacity data are entered into the AESO's Energy Trading System and used to prepare the outage graphs. The outage graphs then assist market participants to formulate market views, with the Monthly Outage Graph being relevant to outages further into the future.

The MSA looked into this matter by communicating with the parties that were involved in submitting the outage information, and by examining the outage data and the forward trading data that the MSA routinely collects. We accept that the rapid changes to the Monthly Outage Graph were caused by human error. The MSA requested and received confirmation in writing from a senior representative of the company that had made the error confirming what had occurred, that extra checking was put into place to try to mitigate future occurrences and that its traders were unaware of the error and thus not in a position to take advantage of the fact.

The changes in the Monthly Outage Graph were mainly driven by a revision of planned outage scheduling of a Power Purchase Arrangement (PPA) unit. For the PPA units, information regarding unit status is sent from the PPA Owner to the PPA Buyer, and the PPA Buyer in turn submits the information to AESO via the Energy Trading System. The Available Capacity values entered into the Energy Trading System by the PPA Buyer ultimately drive the Monthly Outage Graph. What happened in this instance is that the PPA Owner sent the PPA Buyer incorrect outage dates on the afternoon of May 5, 2010, and subsequently discovered and corrected the error the next morning.

The forward transactions made by the PPA Owner did not lead the MSA to believe that there was a breach of FEOC in this incident. This is consistent with our understanding that internal rules exist for that PPA Owner which prevent its traders from communicating with its plant operators.

The MSA believes that human errors of this nature are impossible to completely eliminate, but fortunately occur infrequently. We ask that should such an event occur in the future the applicable participant contact the MSA with relevant details as soon as the error has been identified.

3.1.3 Other Sources of Changes to the Monthly Outage Graph

Another more frequently occurring reason for rapid changes of the Monthly Outage Graph is tied to revisions of outage schedules by a PPA Owner that impact two Buyers. For example, the swapping of planned outages for two units can involve a PPA Owner having to contact two Buyers who then inform the AESO. Small differences in timing of the submissions of the information by the Buyers to the AESO can cause changes close together in time that basically offset each other and can confuse the market.

3.1.4 Possible Remedies

The MSA believes that the frequency of these events can be reduced by the PPA Owner only sending the PPA Buyers such planned outage information after the forward market has closed for the day (i.e. late in the afternoon) and the affected PPA Buyers would then be expected to pass on the information to AESO by early the next morning, say 6 am. This would only apply to outages relevant to the Monthly Outage Graph where it is not critical to AESO's operations to have the information immediately. The requirements of the FEOC Regulation are that participants must keep AESO informed of any changes in planned outages as 'soon as reasonably practicable'. Similar language is likely to be included in the revamped requirements to provide outage information that AESO is preparing to submit to the AUC in the near future. While it may not be fruitful for the MSA to attempt to specify what exactly 'as soon as practicable' means it is clearly intended to be a short time. The PPA Buyers all have 24-hour real-time desks that can input the updated information from the PPA Owner into the Energy Trading System. Provided this was done by, say, 6 am the next morning, the market would not see changes during the trading day. Through this process adjustment, all the changes to the Monthly Outage Graph would occur while the active forward market is closed and not affect trading activity. Possibly all changes to the Monthly Outage Graph could be processed at a set time each day, say 6 am. It would mean that market participants would not be able to trade on this information from the time that it is provided to the AESO until the next day. There is something of a trade off, given that participants would have to delay executing their trading strategies in return for a reduced frequency of occasions when the Monthly Outage Graph suffers rapid changes causing confusion. Hence, this is stated as a suggestion rather than a recommendation and participants are welcome to comment.

4 OPERATING RESERVES

There are three events that occurred in Q2/10 and early July 2010 to comment upon in this report.

4.1 Trading Error on June 23, 2010

On June 23, 2010, an unusual event was observed in the active on-peak regulating reserve market. Just prior to the market closing for the session, at the time that most offers appear on the screen, the AESO observed a new bid in the market. The new bid cleared its volume and influenced the market price. As the only buyer of operating reserves, AESO staff realized straight away that something odd had transpired and immediately informed the Alberta Watt Exchange (Watt-Ex) the operating reserves market trading platform at NGX. The NGX staff quickly established that a new trader for one of the market participants had made an error (inadvertently putting in a 'bid' rather than an 'offer'), and NGX unwound the trade. The market price was corrected and no-one was harmed by the event.

The Watt-Ex trading software was originally designed with the notion of multiple buyers and sellers as a future development to the market; one which has not materialized. Once the operating reserve market evolved with the AESO as the sole buyer, NGX took precautions to limit a trader's privilege to 'offer', with the exception of the AESO having the 'bid' privilege. In the initial set-up for this particular trader, the trading permission was not restricted to 'sell'. Since this event, NGX has checked that all traders have restrictions placed on their trading privileges and have also incorporated a process to avoid this from re-occurring in the future.

4.2 High Stand-by Reserve Prices

Figure C4 in Appendix C shows an increase in stand-by premium prices in the months of May and June, 2010. This price increase was most evident in the on- and off-peak regulating reserves market. The stand-by activation prices of Figure C4 in Appendix C show a significant increase in the same months. Comparing the activation prices with the average Pool prices (Table A1) it is apparent that sellers were generally unwilling to take a big risk, should they be activated, that Pool price would be higher than the activation price.

The opportunity cost for sellers in the active and stand-by operating reserve markets is the energy market. Since the energy market experienced high Pool prices through most of May, higher prices in the active and stand-by operating reserves market during May are to be expected. Persisting high premiums and activation prices in the stand-by market throughout the month of June are more difficult to interpret. It's natural for sellers to attempt to continue to command high prices in the stand-by market, but the absence of any real scarcity should mitigate the situation. On some trading days, the cleared prices in the active reserves markets appear to be less than for the stand-by market, a strange result. As of late July, the stand-by prices appear to have moderated. The MSA will continue to keep a watchful eye on developments in this market.

4.3 AESO Moves to (D-1) Procurement

As announced to the market earlier in 2010, the AESO moved from a five-day to a one-day procurement process commencing on July 6, 2010. This is an interim measure to allow the AESO to undertake its procurement of reserves without unduly influencing the market price.

As of mid July, the procurement of active reserves appears to have fully adjusted to the new set up with no notable problems. There appears to be adequate supply each day for each product. In the next quarterly report we will be able to provide a more complete assessment of this recent development.

5 RETAIL MARKET

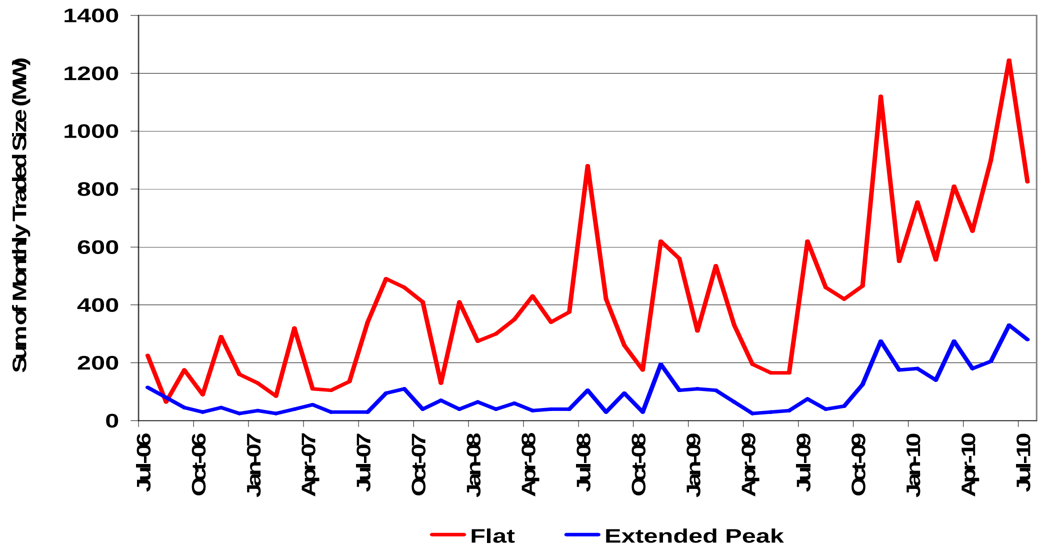
5.1 Evolution of the Regulated Rate Option

The most notable event, occurring at the end of Q2/10, was the transition of the Regulated Rate Option (RRO) for residential and small commercial customers to full short-term pricing akin to that for small natural gas customers. Over the past four years, starting in July 2006, the pricing of the monthly Regulated Rate Option has moved from 100% long-term prices to 100% short-term prices. The final hurdle was cleared with the report to the Minister of Energy by the Electricity Markets Branch Retail Policy Section recommending the full implementation of the transition.[7]

One of the key components that contribute to the belief that the Regulated Rate Option can successfully be based on short-term indices traded on the Natural Gas Exchange is the increasing liquidity of those indices. Figure 5-1 shows the growth in volume of monthly trades on of the flat (7X24 hours) and extended peak (6X16 hours) products. It is apparent that trading volumes have increased over time, particularly for the flat contract.

[7] Government of Alberta, Electricity Markets Branch, Retail Policy Section, 2010, Retail Market Review, An Update and Review of Market Metrics.
http://www.energy.alberta.ca/Electricity/pdfs/RetailMarketReview.pdf

Figure 5-1 Trade Volumes on NGX in the Trading Window for the Regulated Rate Option



5.2 Competitive Retail Offerings

Electricity

The signs of life evidenced in some changes in retail offers to consumers in Q1/10 have continued through Q2/10. As of mid July 2010, consumers have choices in electricity contracts with fixed price offers over one, two, three or five years. Flow-through priced contracts are available from two providers both with no early exit fees. Short-term incentives are being offered such as a discount of 25% off the lowest Regulated Rate Option rate for 6 months at the start of a five year contract.

Natural Gas

Natural Gas contracts are available over one, three and five years at fixed prices as well as price flow-through options.

Dual Fuels (electricity & natural gas)

Several firms offer dual fuel options including combinations where both prices are fixed, and where one is fixed price while the other floats with the market.

Other

Green energy options are available to consumers for both electricity and natural gas.

Overall, the MSA is quite encouraged to see this increased level of activity in the retail market.

6 COMPLIANCE UPDATE

6.1 ISO Rules Compliance Update

Table 6-1 provides an update of the MSA's ISO rules compliance activities as of mid 2010. During the first half of 2010, 24 notices of specified penalty were issued by the MSA. In 28 other instances the MSA chose to forbear and 10 matters remained under review. Additionally, 15 referrals have been addressed through negotiated settlements between the MSA and participants. For comparison, at the end of Q2/09, the MSA had issued 16 notices of specified penalty, 11 forbearances and had 23 files under review.

Table 6-1 Compliance Files (as of end Q2/10)

	Under Review	Notice of Specified Penalty	AUC Administrative Proceedings	Forbearance
6.6	3	10		15
3.5.3	1	4		4
3.5.5		1		
6.3.3	5	9	6	6
6.5.3			8	2
OPP 102			1	1
OPP 606	1			
Total	10	24	15	28

The contravention dates of the 24 notices of specified penalty issued in the first half of 2010 ranged from August 2009 through April 2010 (Table 6-2). Ten of the 24 notices issued were for contraventions of ISO rule 6.6, occurring across five different months. Additionally, nine of the 24 notices issued were for contraventions of ISO rule 6.3.3, eight of which occurred in 2009. Twenty-two of the Notices of Specified Penalty issued in the first half of 2010 related to matters referred to the MSA by the AESO – the remaining two notices of specified penalty related to a matter self reported to the MSA. One of these matters was reported prior to the MSA's self-reporting initiative and the other matter did not meet the MSA's self-reporting requirements that assure forbearance.

Table 6-2 Compliance Files by Month of Contravention

		2009					2010						Total
	Rule	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	
Under Review	6.6								2			1	3
	3.5.3											1	1
	3.5.5												0
	6.3.3					4		1					5
	6.5.3												0
	OPP 102												
	OPP 606								1				1
	Total					4		1	3			2	10
NSP	6.6		4	1		1	3	1					10
	3.5.3					1		2	1				4
	3.5.5			1									1
	6.3.3	2	1		1	4				1			9
	6.5.3												
	OPP 102												
	OPP 606												
	Total	2	5	2	1	6	3	3	1	1			24
Forbearance	6.6					3		2	6	1	2	1	15
	3.5.3										4		4
	3.5.5												
	6.3.3							1	1	2	2		6
	6.5.3	1							1				2
	OPP 102									1			1
	OPP 606												
	Total	1						3	8	4	8		28

Table 6-2 further segments the second, third and fifth columns of Table 6-1 by the month of the occurrence of the contravention.

6.2 Emerging ISO Rules Non-Compliance Trends

At the beginning of Q2/10, the MSA offered an additional incentive for self reporting of non-compliance matters provided certain criteria are met. The MSA has subsequently seen a significant increase in the number of matters being self reported. Of the 77 ISO rules compliance files the MSA has reviewed in the first half of 2010, 30 of those files have been self reported. Twenty-five of these 30 files were self reported in Q2/10. Of the 30 total self reports in 2010, all but two cases were forborne as noted in Section 6.1. In 2009, 21 matters were self reported through the entire year. Market participants can self report ISO rules compliance matters to the MSA's compliance email address at: compliance@albertamsa.ca with a copy to the AESO at: marketcompliance@aeso.ca.

6.3 Reliability Standards Compliance Update

During Q2/10, the MSA received its first six self reported compliance matters relating to reliability standards. All the reports used the MSA's standard reporting forms and five included mitigation plans. The MSA extended conditional forbearance on three of these six matters based upon completion of the proposed mitigation plans. In all three cases, the mitigation plans were successfully completed. The remaining three matters remain under review. Three of the six self reports related to FAC-003-AB-1. The remaining three self reports related to the following three standards: CIP-001-AB-1, PRC-004-WECC-1 and EOP-004-AB-1.

All registered entities (except the AESO) can self report Reliability Standard compliance matters to the MSA's compliance email address at: compliance@albertamsa.ca with a copy to the AESO at rscompliance@aeso.ca. The AESO follows a separate process for self reporting to the MSA.

6.4 Compliance Process Document

In addition to its regular compliance enforcement activities during Q2/10, the MSA commenced a stakeholder consultation process on April 23, 2010 with the publication of a strawdog draft compliance process document covering both ISO rules and Alberta reliability standards. As part of the consultation process, stakeholders were invited to provide comment on the strawdog. On June 1, 2010, the MSA posted a revised draft together with a written response to comments received from stakeholders. On June 14, 2010, remaining timelines were extended to provide stakeholders with additional time to consider and comment on the revised draft and to accommodate a June 24, 2010 stakeholder compliance roundtable requested by participants at which the MSA provided further clarification of its views regarding compliance enforcement. Stakeholders can review progress of this consultation process at http://www.albertamsa.ca/1120.html. The consultation process is currently scheduled to conclude with the publication of a final process document on August 6, 2010.

In the interim, the MSA has advised participants and registered entities to use MSA standard forms introduced as part of the MSA compliance process, for purposes of self reporting and filing of mitigation plans. Participants and registered entities maximize their chances of receiving forbearance by self reporting in accordance with the framework presented in the stakeholder consultation process.

7 MSA ACTIVITIES

7.1 Stakeholder Consultation Process on Participants' Offer Behaviour

In Q1/10, the MSA initiated a stakeholder consultation process on participants' offer behaviour. The process started with a Roundtable discussion on issues identification on February 18, 2010. Based on the understanding developed through the Roundtable discussion and stakeholders' comments, on April 27, 2010 the MSA released a discussion paper that identified the foundational elements that shape the MSA's approach to offer behaviours.[8] The MSA published a second paper outlining an analytical framework to be used to assess participants' offers on June

[8] MSA, 2010, 'Foundational Elements Shaping the Market Surveillance Administrator's Approach to Bids and Offers'. http://www.albertamsa.ca/files/Foundational_Elements_100427.pdf

17, 2010.[9] Another Roundtable discussion was held on June 25, 2010 and market participants have until July 30, 2010 to provide any written feedback they may have. The MSA hopes to move through the stakeholder consultation process to develop a Guideline on offer behaviour by the end of 2010. Work is underway on the development of hypothetical examples to illustrate some of the finer points of the MSA's intended enforcement approach. The examples will be drafted with the aid of market participants and then discussed in a stakeholder workshop.

7.2 Market Share of Offer Control

The Fair, Efficient and Open Competition Regulation came into force on September 1, 2009. As per the requirements of the FEOC Regulation, the MSA collected offer control information from all market participants with a market share more than 5%. The results of that exercise were published in a brief report on June 28, 2010.[10]

The MSA is very pleased with the results of this process. We see the Alberta electricity market as a public market and, as such, it seems reasonable that all participants should know which participants control which assets. Control of offers is more relevant to price formation in the market than ownership of the asset.

7.3 Financial Electricity Market Report

The forward market for electricity in Alberta is still in a formative stage. It is an important element in the overall electricity market structure – some participants would say it is the market. On April 9, 2010 the MSA published a report on the forwards market that provides a general description of its structure, the various reasons that entities might trade and the different trading platforms, as well as an overview of the data that has been collected in the past two years.[11]

7.4 AUC Proceedings

Q2/10 saw the AUC addressing various matters of significance to the MSA, including:

- Settlement Applications filed with the AUC, including requests for confidentiality; and,
- Information Sharing orders in the context of the Power Purchase Arrangements (PPAs).

[9] MSA, 2010, 'Analytical Framework for the Monitoring of Bids, Offers and Market Health'. http://www.albertamsa.ca/files/MSA_Discussion_Paper2_061710.pdf
[10] MSA, 2010, 'Market Share Offer Control, 2010'. http://www.albertamsa.ca/files/MSOC_2010_062810(2).pdf
[11] MSA, 2010, 'An Introduction to Alberta's Financial Electricity Market'. http://www.albertamsa.ca/files/Financial_Electricity_Market.pdf

7.4.1 Settlement Applications, including requests for confidentiality

The AUC issued decisions on two separate applications which involved, by way of preliminary motion, requests for confidentiality regarding proposed settlements. Those were:

- Decision 2010-210, in relation to a request for confidentiality brought by the MSA and Syncrude Canada Ltd.; and,
- Decision 2010–268, in relation to a request for confidentiality brought by the MSA and NorthPoint Energy Solutions Inc.

In each case confidentiality was sought on the basis that the settlement brought to the AUC for approval reflected negotiations conducted on a 'without prejudice' basis, and that it would be in the public interest for the AUC to maintain confidentiality around critical content until its decision on the settlement was issued.

As set out by the MSA in its submissions to the AUC, this approach to proposed settlements is consistent with how such matters are handled in some other jurisdictions, and in the view of the MSA would tend to facilitate resolution of issues by agreement rather than litigation.

In relation to these particular proceedings, the AUC was not convinced that confidentiality for the 'without prejudice' content of the settlements was warranted. Accordingly, the AUC denied the requests for confidentiality.

Given that the proposed settlements were, to a degree, predicated upon that confidentiality, the parties withdrew the settlements to consider their next steps. The MSA will continue to explore the avenues available to it that are administratively efficient and promote a collaborative approach to compliance among market participants.

7.4.2 Information Sharing orders in the context of the Power Purchase Arrangements (PPAs).

Section 3 of the *Fair, Efficient and Open Competition Regulation* (FEOC Regulation) prohibits the preferential sharing of certain information (price and quantity offers) except in prescribed circumstances, including where the AUC has issued an order permitting the sharing of such records pursuant to subsection 3(3) of that enactment.

The MSA is given notice of any application seeking such an order, and can participate in the related proceeding (which otherwise is kept private). In all cases to date the MSA has intervened, in some cases to support the application and in others to object to the application.

Once such application, Proceeding ID 462, was brought by the Balancing Pool, and resulted in Decision 2010-233 issued by the AUC on May 31, 2010. The Balancing Pool (as Buyer of the Genesee PPA) sought approval to share price and quantity offer information with Capital Power Generation

Services Inc. (Capital Power), a subsidiary of Capital Power Corporation (the Owner of Genesee PPA), pursuant to an ”agency arrangement” between the parties. In its submissions to the AUC the MSA supported the application and proposed order.

In its decision, the AUC highlighted concerns underlying this area of FEOC Regulation, including as follows:

> The sharing by two market participants of their non-public records has the potential to allow collusion and price-fixing by these participants, especially if the two participants have a substantial market share or market power. Such collusion can be harmful to the marketplace as a whole, especially consumers. It is, therefore, incumbent upon the Commission to carefully scrutinize record-sharing agreements in order to maintain the competitive environment that the Electric Utilities Act so ardently emphasizes as its goal.

The decision noted that under the Genesee PPA, the Balancing Pool has the option to set up its own fully staffed direct dispatch centre, or to enter into an agreement that will satisfy the requirement to provide 24-hour real time energy restatements for the operation of the Genesee 1 and Genesee 2 generating units. The MSA understands that, while not expressly referenced in the decision, this is contemplated in Schedule J of the PPA.

The Balancing Pool entered into an agreement whereby Capital Power provides energy management services regarding the Genesee 1 and 2 generation units, including a 24-hour real time trading desk service for operational, ancillary service, dispatch down service and energy restatements, and acting as a single point of contact to confirm operational information and monitor the units’ operations. Sharing of price and quantity offer information is part of that agreement.

The AUC was satisfied that an order was required to permit the proposed information sharing; that the sharing of the records was reasonably necessary for the Balancing Pool to carry out its business; and that the records will not be used for any purpose that does not support the *fair, efficient and openly competitive* operation of the market. The AUC approved the information sharing accordingly.

A second application, Proceeding ID 514, dealt on a generic basis with information sharing in the context of the PPAs, and resulted in Decision 2010-293 issued by the AUC on June 24, 2010.

The AUC described the issues in that proceeding as follows:

- Whether the PPAs are an “enactment” within the meaning of subsection 3(2) of the FEOC Regulation; and,
- If so, whether the provisions of the PPA “require or permit” the sharing of information by a market participant with another person?

Both of those issues go to the interpretation of subsection 3(2)(e) of the FEOC Regulation, and ultimately to whether information sharing pursuant to the PPAs would be constrained by section 3 of that regulation.

The proceeding was initially focused on two types of capacity which relate to PPA generating units: “Increased Capacity” and “Excess Energy”, but the AUC invited submissions on whether the proceeding should be expanded to also consider the third and largest type of PPA capacity, “Committed Capacity”.

In its submissions the MSA urged the AUC to take an interpretation which would require AUC approval for the sharing of non-public price and quantity offer information in the context of the PPAs. The MSA raised the concern that another interpretation could render a large portion of Alberta generation outside the ambit of the general prohibition against sharing of competitively sensitive information.

On the first issue, the AUC found that a PPA is considered to be an “enactment” for the purposes of subsection 3(2)(e) of the FEOC Regulation. Having made that finding, the AUC considered the extent to which the PPAs permitted or authorized the sharing of records; in other words, what the scope of the exemption in subsection 3(2)(e) would then be.

The AUC found that while the PPAs address three types of capacity, the PPAs only contemplate the sharing of records in two limited circumstances, Excess Energy and Increased Capacity (thus, not in respect of “Committed Capacity”).

Accordingly, the AUC decided that the exemption in subsection 3(2)(e) of the FEOC Regulation applied in relation to non-public price and quantity offer information for Excess Energy and Increased Capacity. No AUC approval would be required for the sharing of such records.

Insofar as “Committed Capacity” is concerned, the decision can be read along with Decision 2010-233 to say that information sharing in relation to that type of PPA capacity remains subject to AUC approval pursuant to subsection 3(3) of the FEOC Regulation.

The decision also provided helpful clarity on the characterization of the PPAs, which is relevant to the enforcement provisions within the Alberta Utilities Commission Act. With the support of various parties in the proceeding, the AUC made clear that PPAs are enshrined as part of the Power Purchase Arrangements Determination Regulation and by their status have the force of a regulation.

7.5 Association of Market Monitors

In April 2010, the MSA participated in the semi-annual meeting of EISG (Energy Inter-Market Surveillance Group) wherein matters of mutual interest are discussed. The MSA has found this to be a very effective organization to be involved with as it allows us to share experiences and learn from each other. Representatives cover all the North American electricity markets plus several off-shore markets including Australia, Colombia and the Philippines.

7.6 Transition of Reports to AESO

On May 1, 2010, the MSA ceased publishing its Daily Snapshot and weekly Market Monitor reports. The transition of this responsibility to the AESO was coordinated so that there was no gap in reporting. The AESO has begun publishing very similar reports on its web site and market participants are encouraged to refer to them.[12]

The change is consistent with the MSA's philosophy that the AESO is the most obvious source of factual data regarding the markets that it operates. Similarly, the MSA will develop a sharper focus on the measurement and assessment of competition in the electricity and retail natural gas markets. The time savings resulting from the removal of reporting responsibility will contribute to this effort.

[12] The reports are available on the AESO's web site (www.aeso.ca) by following the following links:
Market and System Reporting > Current and Historical Market Reports > Historical > Weekly Market Report
Market and System Reporting > Current and Historical Market Reports > Historical > Daily Market Report

APPENDIX A – WHOLESALE ENERGY MARKET METRICS

Table A1 Pool Price Statistics

	Average Price[1]	On-Pk Price[2]	Off-Pk Price[3]	Std Dev[4]	Coeff. Variation[5]
Apr-10	49.71	61.51	33.57	53.32	107%
May-10	134.69	193.55	60.03	223.19	166%
Jun-10	57.27	79.44	26.93	100.43	175%
Q2-10	**81.15**	**111.50**	**40.69**	**150.68**	**186%**
Jan-10	43.43	50.84	34.03	15.56	36%
Feb-10	43.90	49.30	36.69	14.33	33%
Mar-10	35.31	43.41	24.07	31.64	90%
Q1-10	**40.78**	**47.75**	**31.52**	**22.52**	**55%**
Apr-09	31.53	38.56	21.91	35.58	113%
May-09	31.91	39.73	22.01	27.87	87%
Jun-09	33.48	45.09	17.60	43.82	131%
Q2-09	**32.30**	**41.12**	**20.54**	**36.26**	**112%**

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 A1 Pool Price Duration Curves

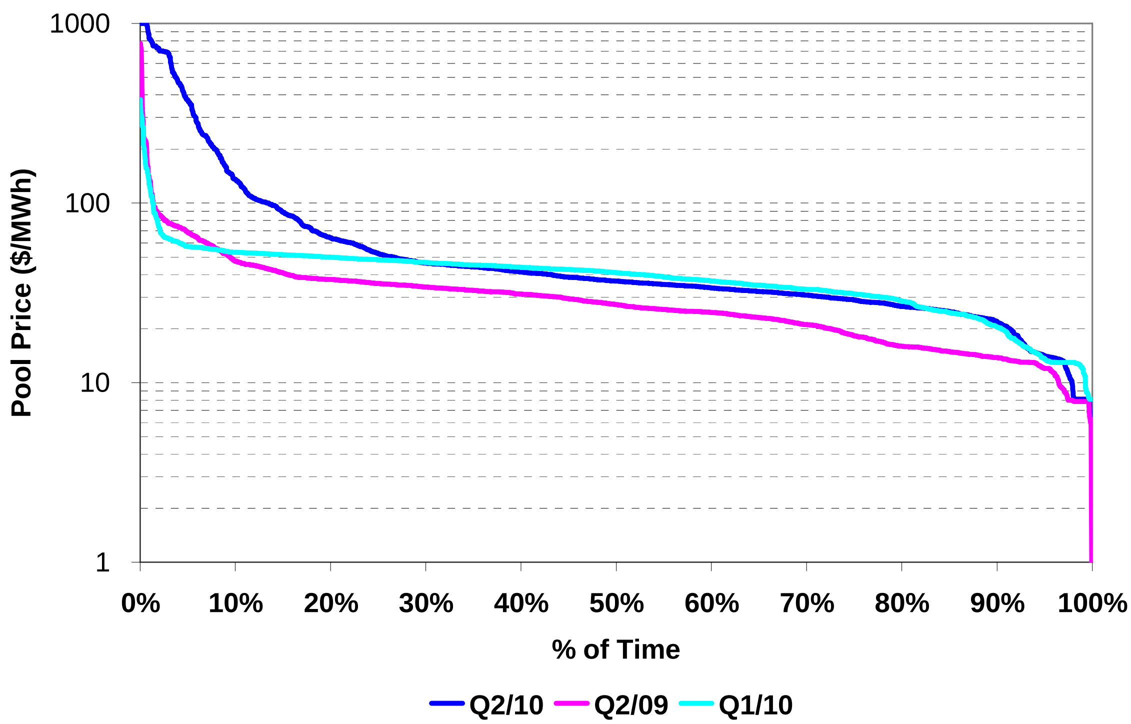
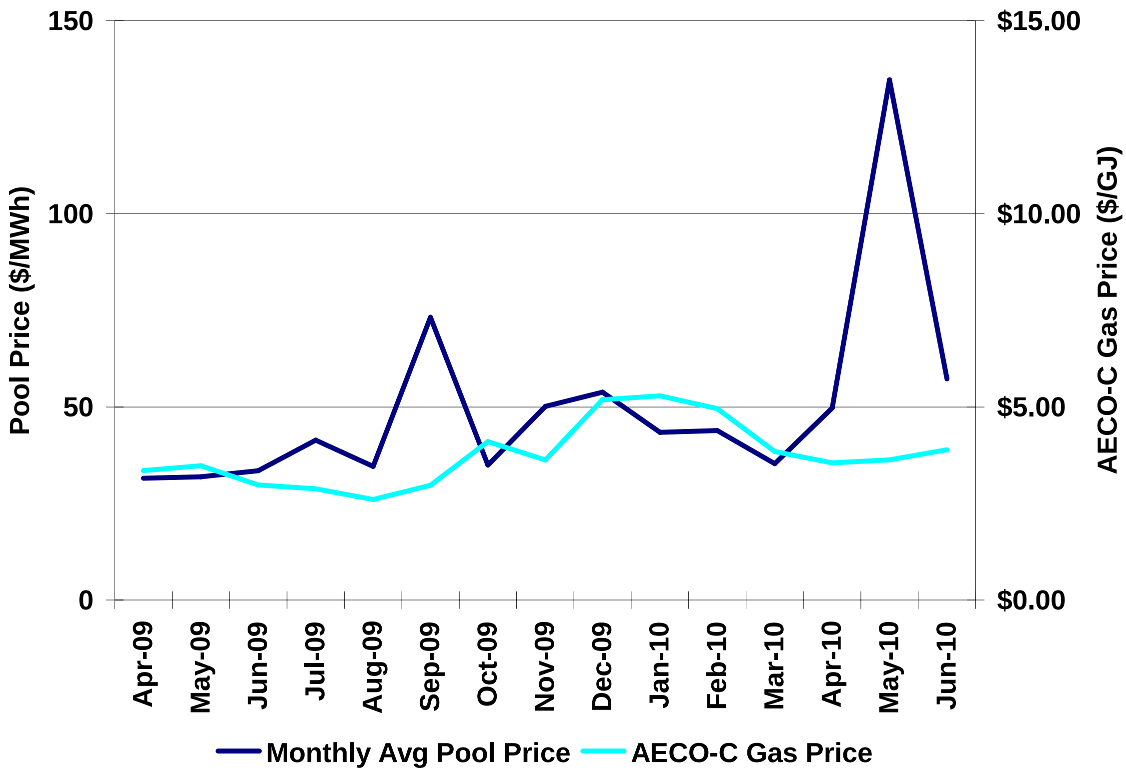


Figure A2 Pool Price with AECO Gas Price

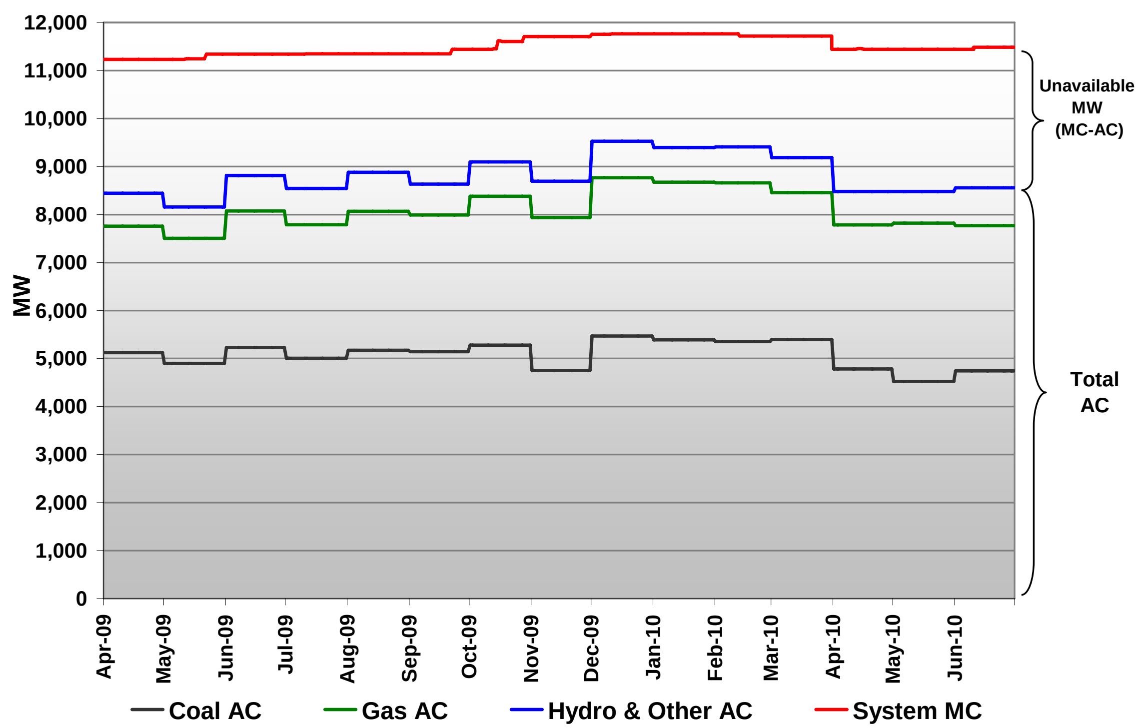


APPENDIX B – SUPPLY AVAILABILITY METRICS

Table B1 Availability Factor and Capacity Factor

Fuel Type	Quarter	Average MC	Average AC	Availability Factor	Generation	Capacity Factor
		[A]	[B] MW	[C]=[B]/[A]	[D]	[E] = ([D]x1000)/([A]xhrs)
		(MW)	(MW)	(%)	(GWh)	(%)
All Fuels *(excl. Wind)*	Q2/10	11,454	8,505	74%	14,687	59%
	Q1/10	11,739	9,331	79%	16,304	64%
	Q2/09	11,282	8,468	75%	14,728	60%
Coal	Q2/10	5,782	4,682	81%	9,123	72%
	Q1/10	6,054	5,379	89%	10,970	84%
	Q2/09	6,011	5,081	85%	9,955	76%
Natural Gas	Q2/10	4,754	3,110	65%	5,097	49%
	Q1/10	4,768	3,216	67%	4,934	48%
	Q2/09	4,356	2,696	62%	4,315	45%
Hydro & Other	Q2/10	917	712	78%	467	23%
	Q1/10	917	735	80%	400	20%
	Q2/09	915	691	76%	458	23%
Wind	Q2/10	629	n/a	n/a	349	25%
	Q1/10	600	n/a	n/a	448	35%
	Q2/09	497	n/a	n/a	307	28%

Figure B1 Availability Capacity (AC) vs Maximum Capacity (MC)



APPENDIX C – OPERATING RESERVE MARKET METRICS

Figure C1 On-Peak Active Settlement Prices - All Markets (NGX and OTC)

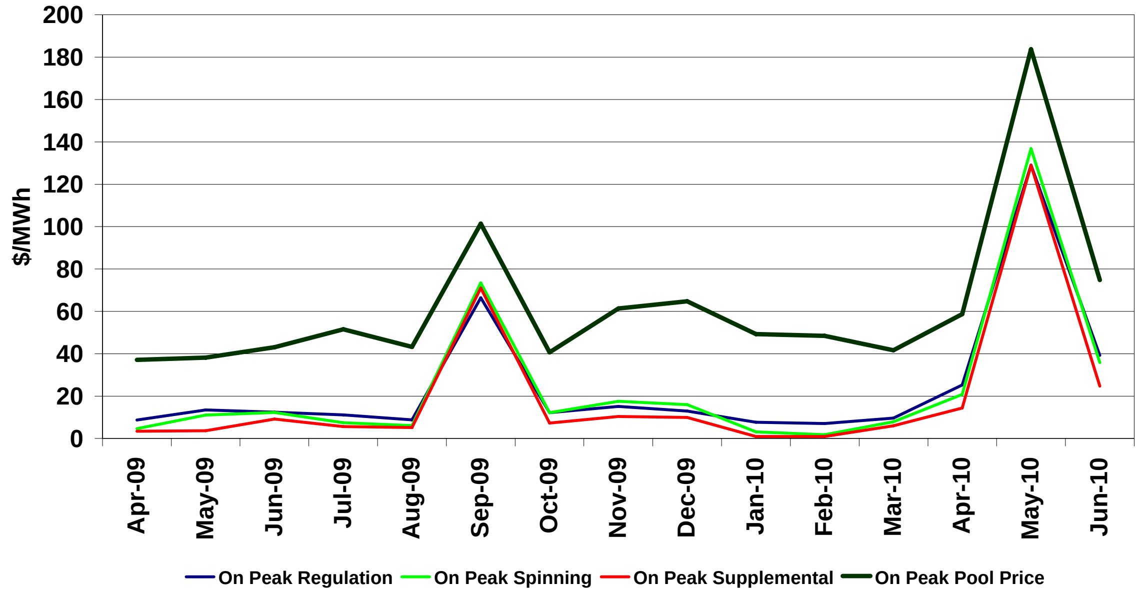


Figure C2 Off-Peak Active Settlement Prices - All Markets (NGX and OTC)

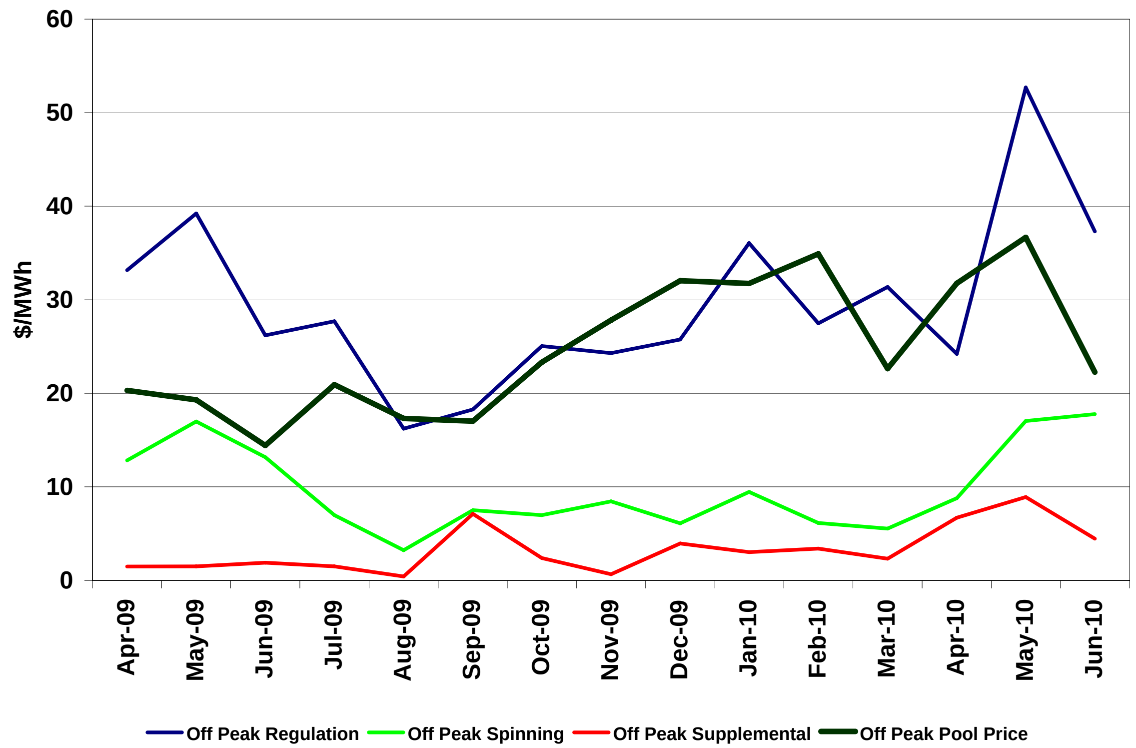


Figure C3 Active Reserves Weighted Average Trade Index

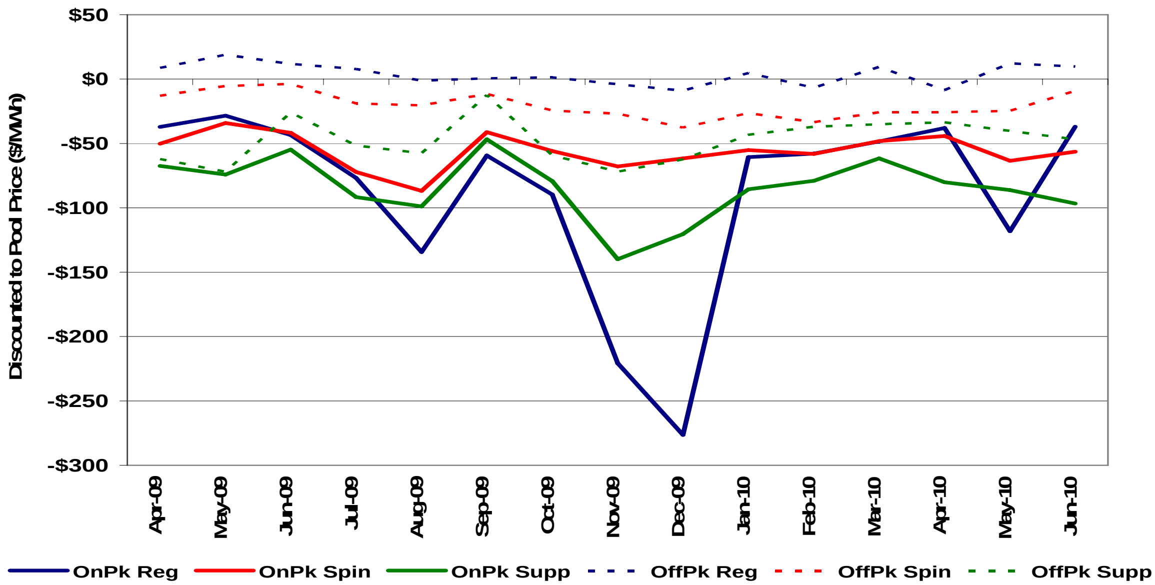


Figure C4 Standby Premiums - All Markets (NGX and OTC)

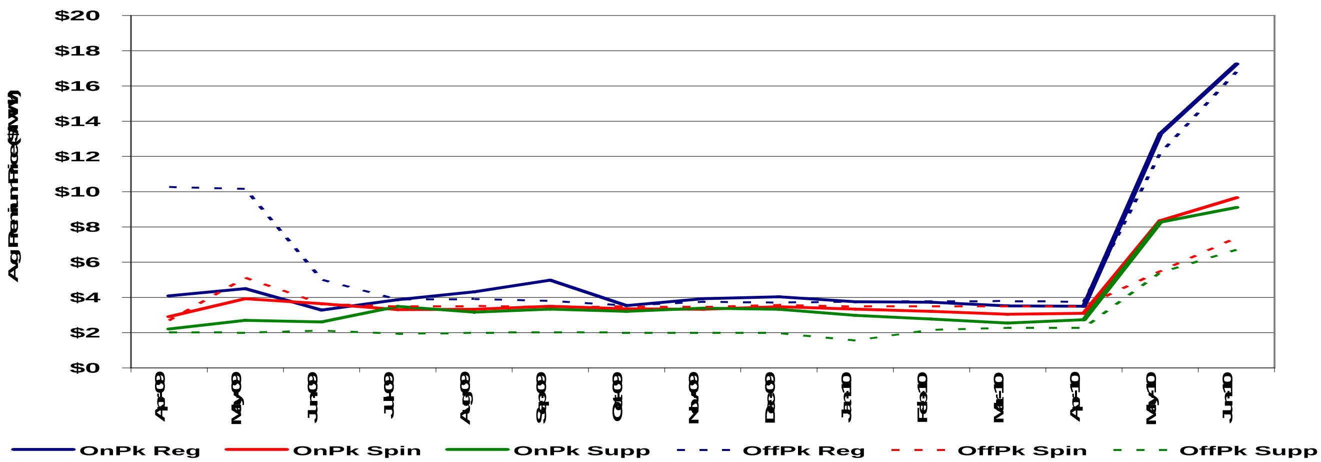


Figure C5 Standby Activation Prices - All Markets (NGX and OTC)

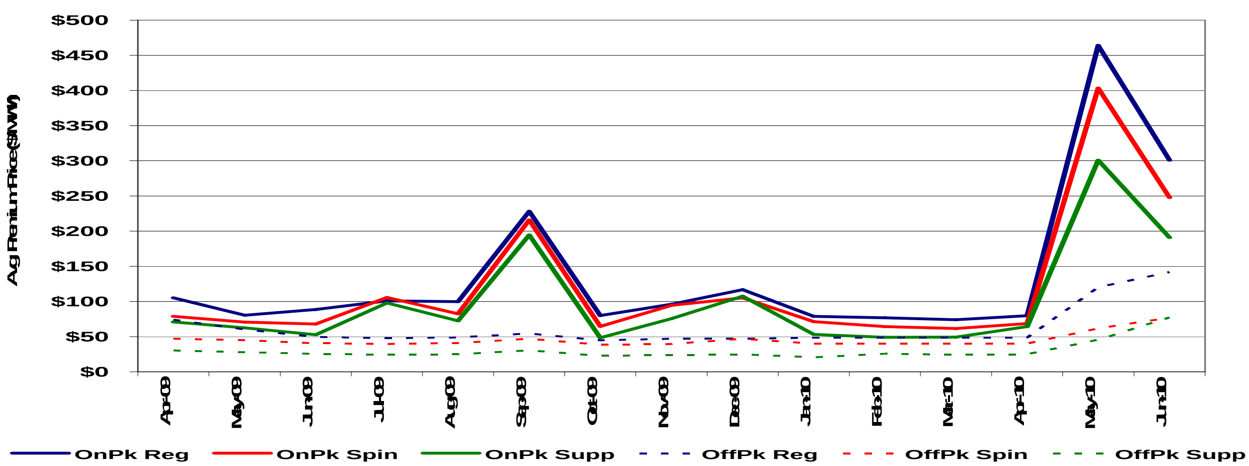


Figure C6 Active Regulating Reserve Market Share by Fuel Type

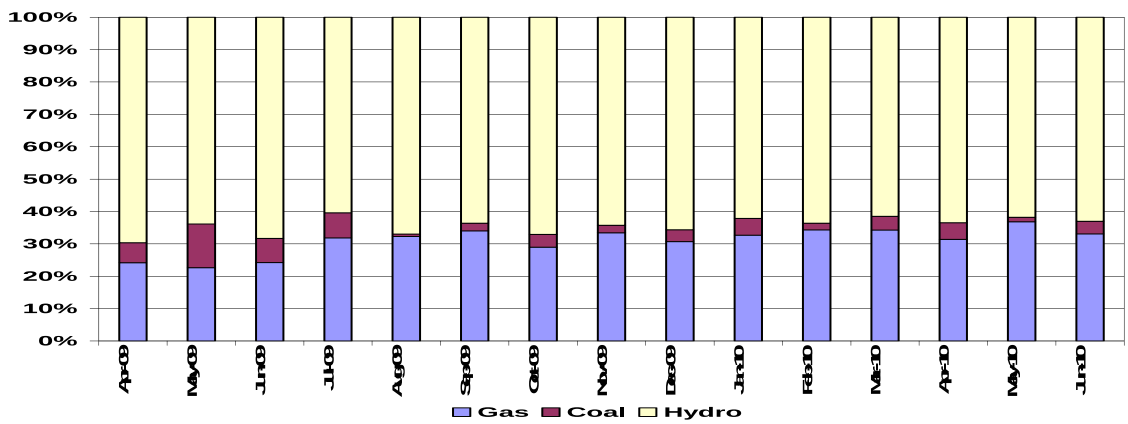


Figure C7 Active Spinning Reserve Market Share by Fuel Type

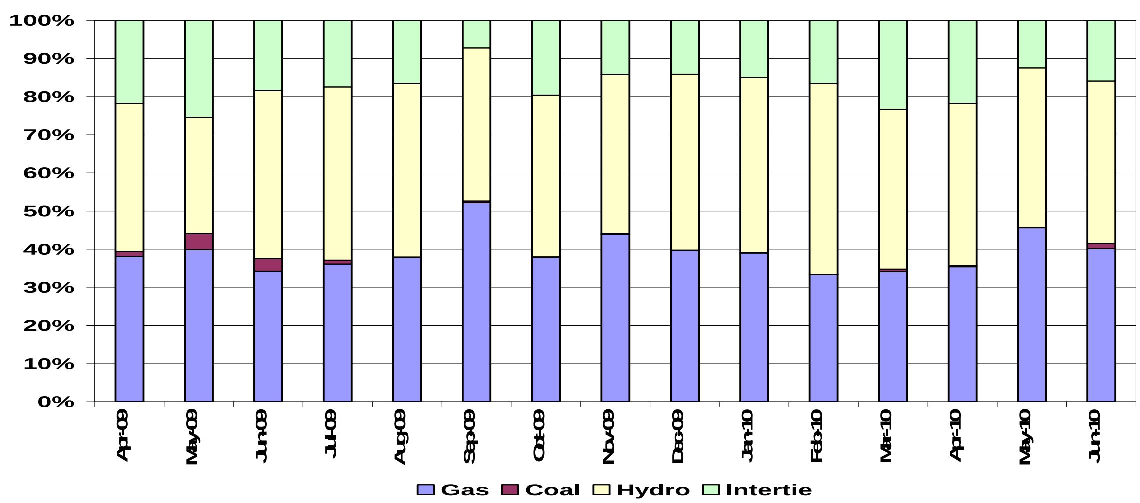
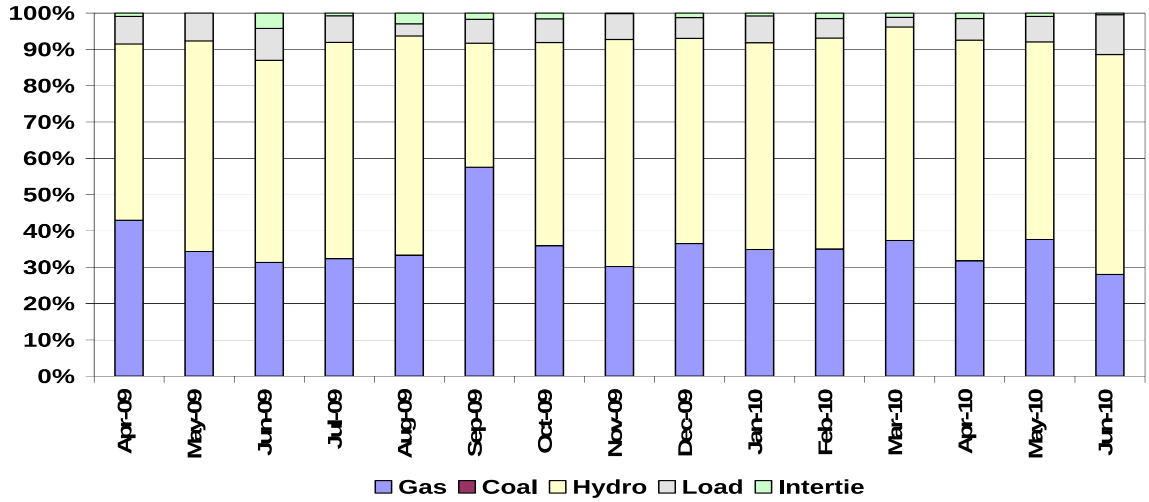


Figure C8 Active Supplemental Reserve by Fuel Type



APPENDIX D – DDS METRICS

Figure D1 Average Daily TMR, Eligible, Constrained & Dispatched DDS Volumes (MW)

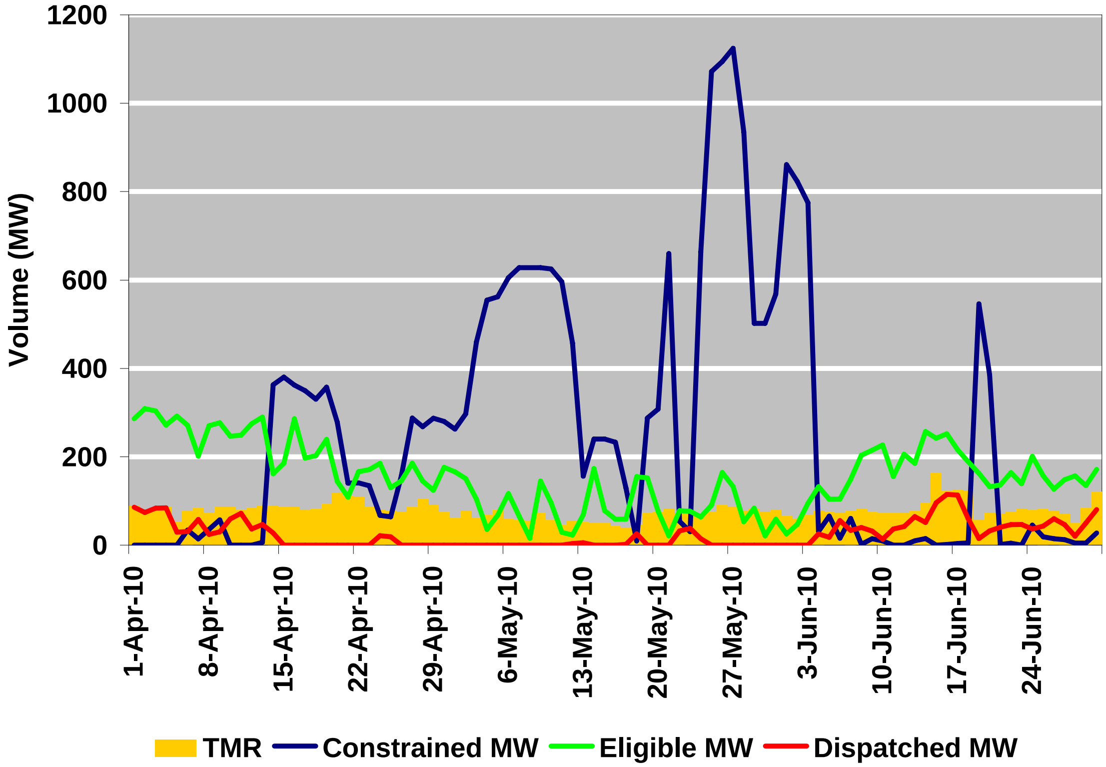
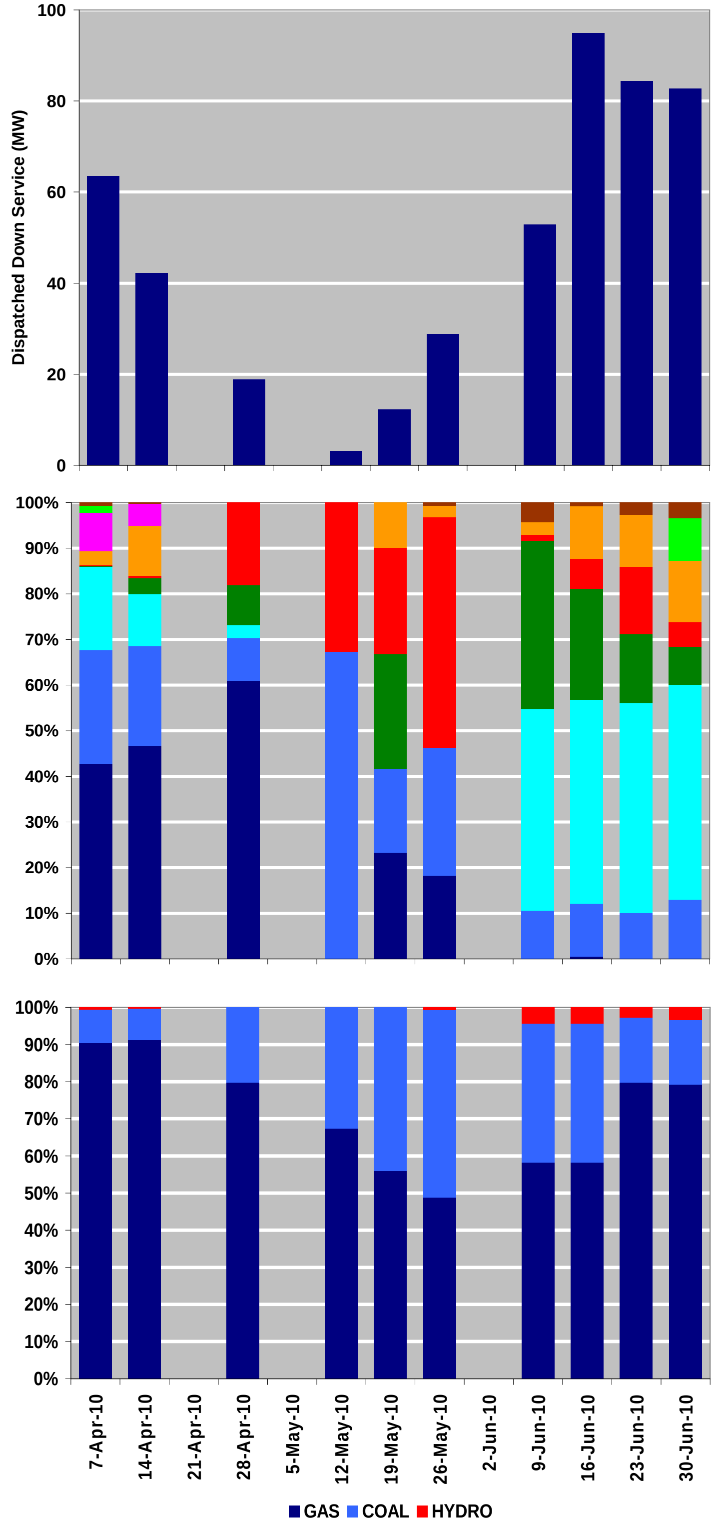


Figure D2 Average Weekly DDS Volume, Market Share by Participant and by Fuel Type

Average Weekly DDS Volume

Average Weekly DDS Market Share by Participant

Average Weekly DDS Market Share by Fuel Type



APPENDIX E – INTERTIE METRICS

Figure E1 Intertie Utilization

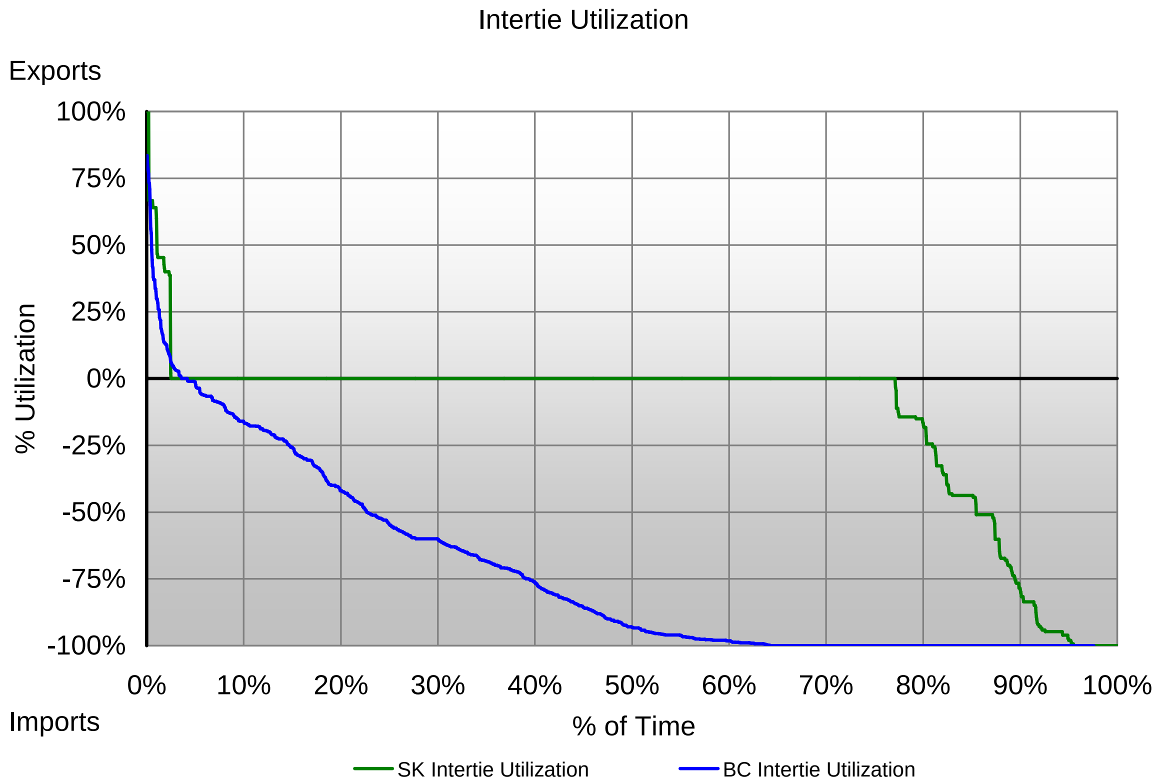


Figure E2 On-Peak Prices

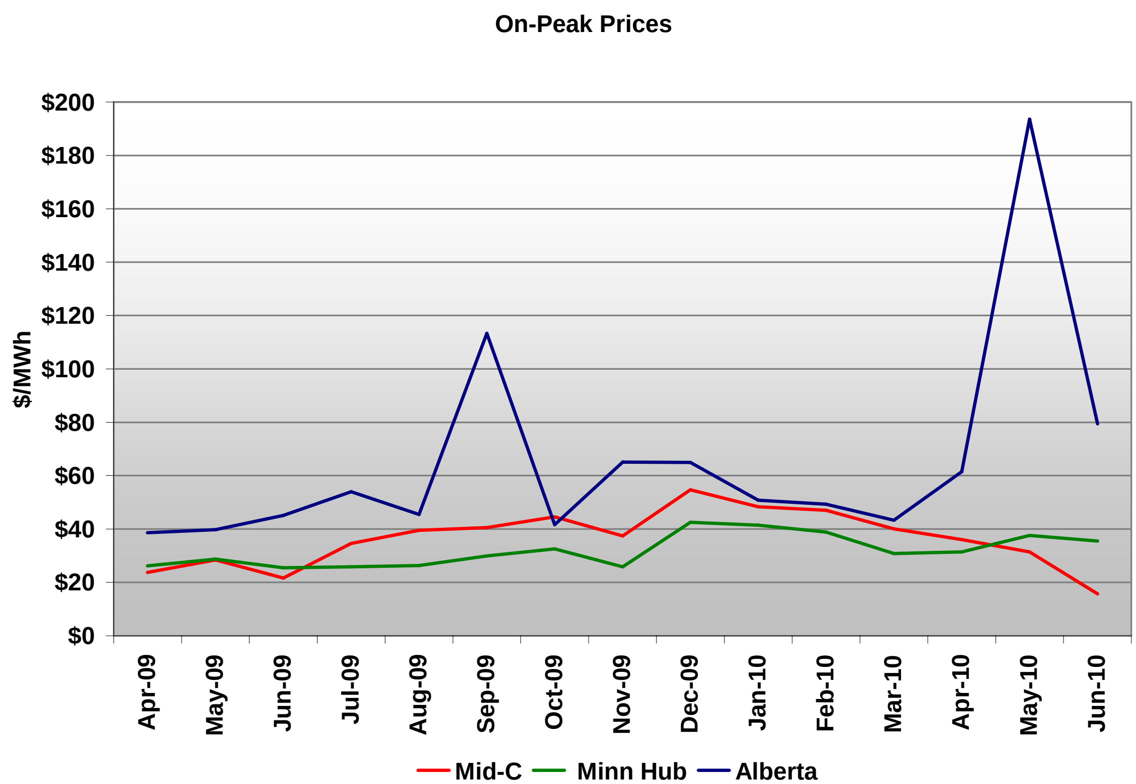


Figure E3 Off-Peak Prices

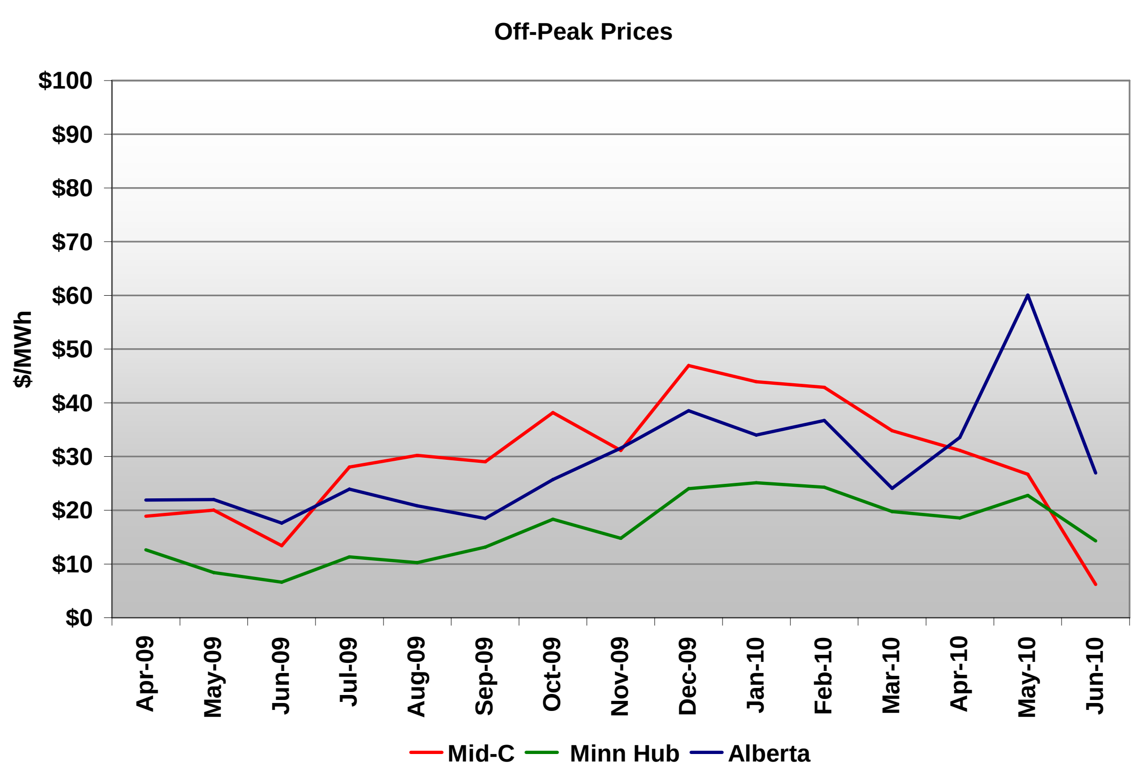


Figure E4 BC Intertie Price Differential and Net Flow

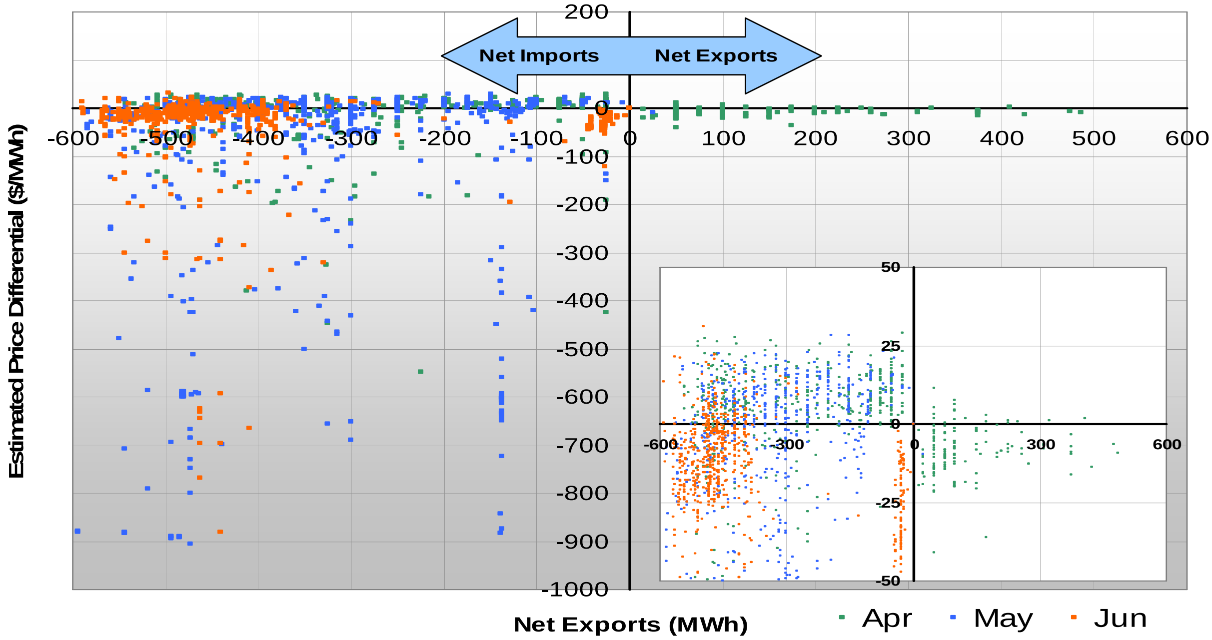


Figure E5 SK Intertie Price Differential and Net Flow

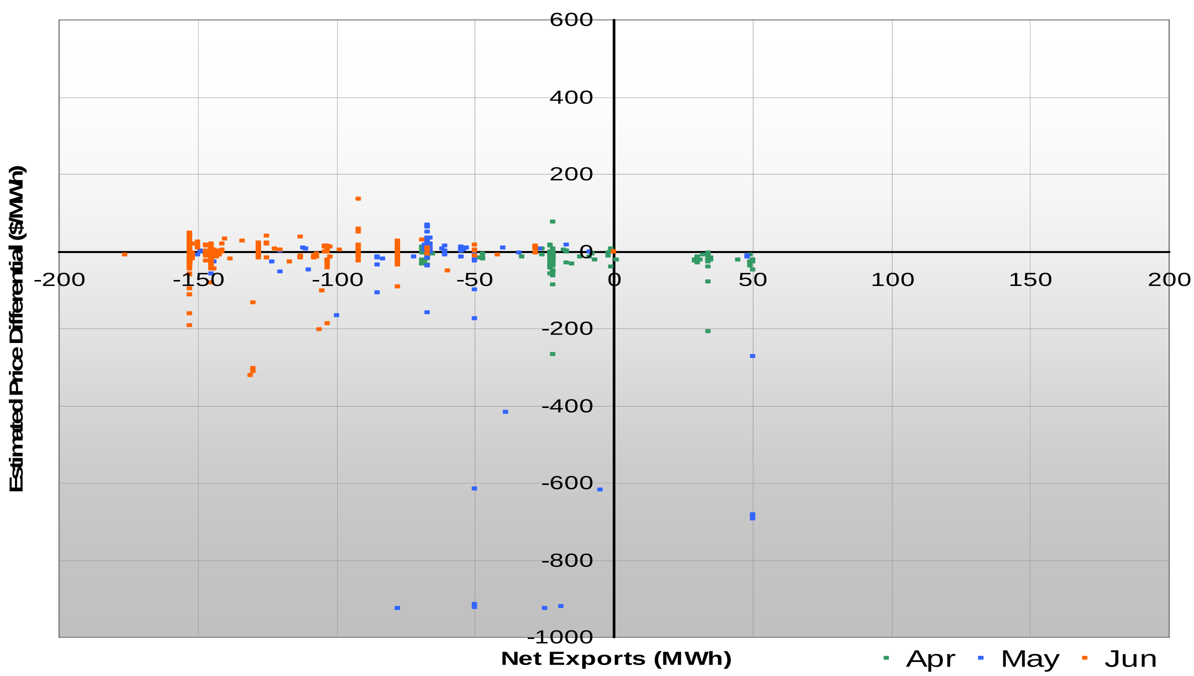
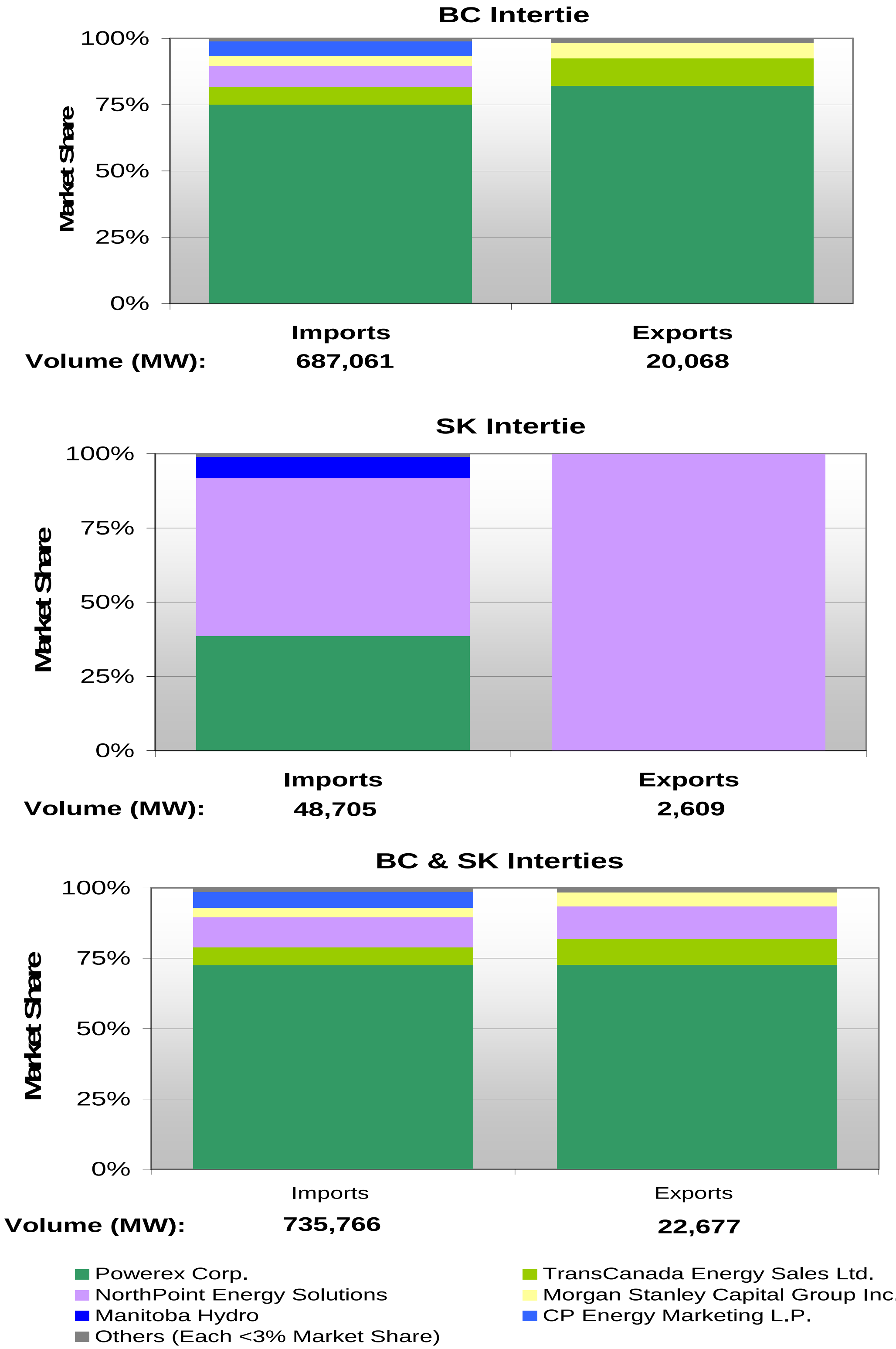


Figure E6 Intertie Market Share



APPENDIX F – FORWARD MARKET METRICS

Figure F1 Volume by Trading Month[13]

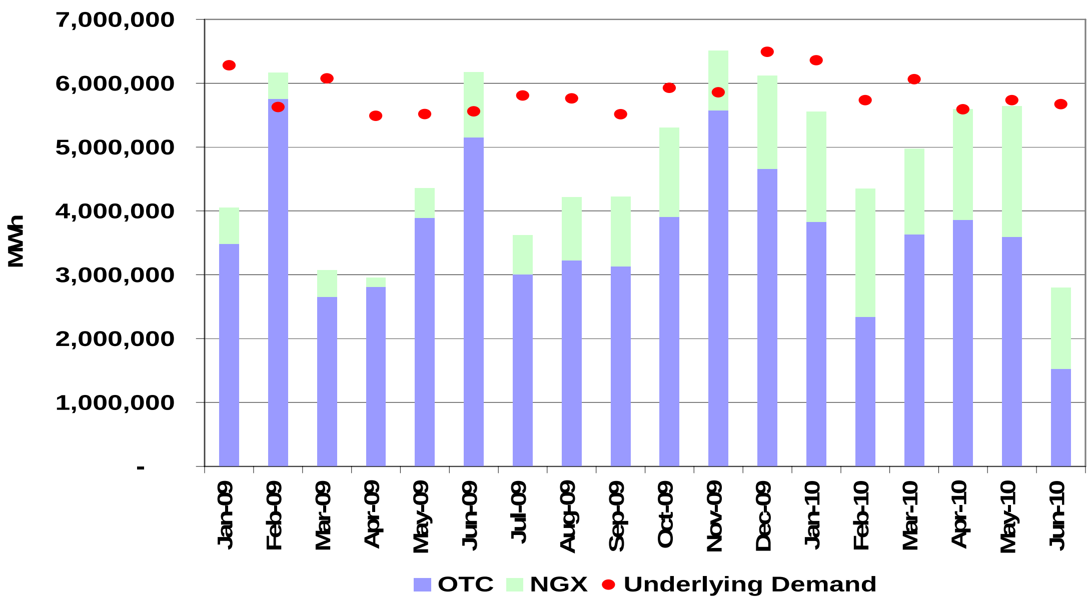
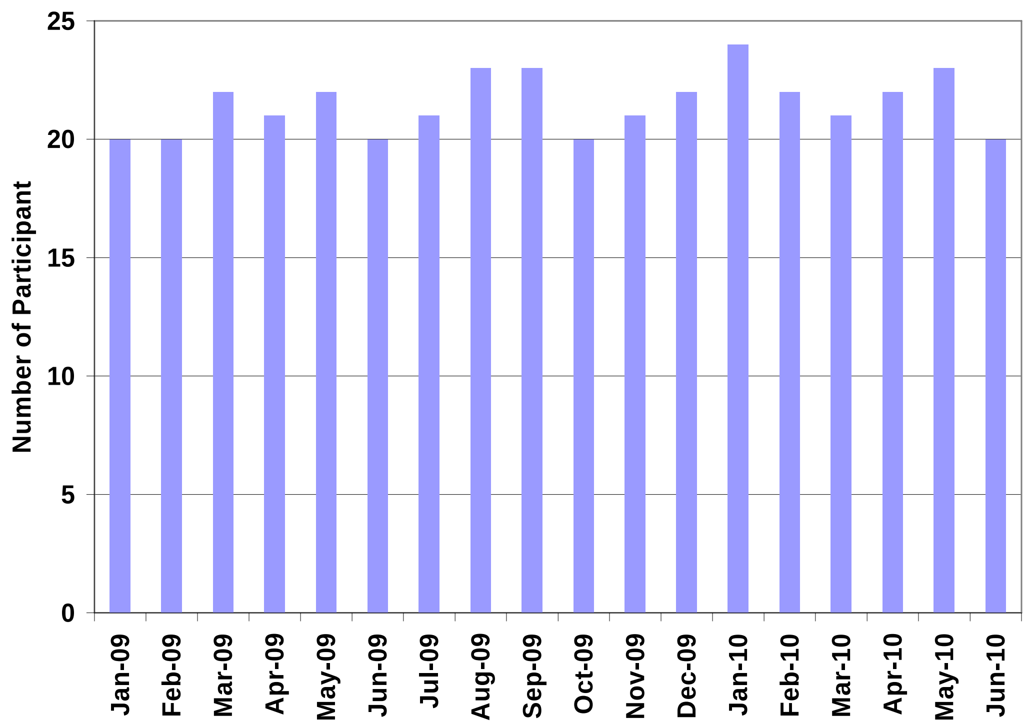


Figure F2 Number of Participants by Trading Month



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