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MSA REPORT

2008 Year in Review

14 May, 2009

MARKET SURVEILLANCE ADMINISTRATOR

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

The MSA Year-in-Review is a complementary report to the MSA annual report and contains a broad technical review of market outcomes during 2008 and highlights from various studies conducted by the MSA through the year.

Some important features of 2008 include:

- Average wholesale price in 2008 was $89.95/MWh compared with $66.95/MWh in 2007.
- Monthly average prices ranged from $64.51/MWh in July to $135.95/MWh in April.
- Price volatility in 2008 as measured by coefficient of variation was comparable to prior years.
- Key events that drove price this year were the KEG Conversion project, moderate summer temperatures, unit outages in the fall and a combination of the SVC outage and very cold weather late in the year.
- Growth of summer peak loads is such that in the near future Alberta could well be a summer peaking system.
- Growth in average load has slowed down significantly over the past few years.
- The correlation between Pool price and natural gas price has weakened over the past several years. Plant availability and wind are now key drivers of Pool price.
- Net revenue analyses for four different types of hypothetical new entry showed encouraging returns in 2008. New plants are being built in the next two years consistent with the net revenue analysis.
- An assessment of 'Quick Hits' one year on confirms much of what the MSA has said previously on the subject. Payments to suppliers on the margin have been very moderate with a somewhat surprising outcome that TMR providers tend to get larger payments.
- Improved access to forward market data has allowed the MSA to make a somewhat more detailed analysis in 2008. Market liquidity is reasonable with the highest liquidity in the monthly and quarterly term products.
- The retail analysis this year is limited and a reader wishing more details should review the recent retail report posted at www.albertamsa.ca/files/Public_Retail_Report_021309(1).pdf
- The AESO procured more active reserves in 2008 on (D-1) than in prior years in part to prove out that sellers would be there in sufficient quantity, as contemplated in the redesign effort currently

ongoing. Overall, the testing was successful and bodes well for the redesign.

- This was the MSA’s first year in its role as enforcer of ISO rules compliance. Over the year, 21 sanctions were issued including 7 financial penalties of which two were disputed before the AUC. The disputed penalties were both confirmed by the AUC.
- The MSA used its Stakeholder Consultation Process three times in 2008, resulting in an Intertie Conduct Guideline, a revision to the MSA’s Investigation Procedures and an evaluation of the consultation process.

1 FEATURED WHOLESALE MARKET DEVELOPMENTS

1.1 Wholesale Market Prices

Average Pool price in 2008 was $89.95/MWh, up 35% from the value of $66.95/MWh in 2007. The range in monthly average price was quite substantial again, from a low of $64.89 in February to a high of $135.95 in April. Volatility as measured by coefficient of variation was comparable to prior years.

In terms of market heat rate (HR = Pool price/Natural Gas price), the average for the year was 12.2 GJ/MWh, similar to recent years (11.4 GJ/MWh in 2007 and 13.9 GJ/MWh in 2006). In Alberta the applicable price for natural gas is AECO-C. The price of natural gas varied appreciably over the year, starting at about $7/GJ in January, gradually rising to more than $10/GJ in June, reducing over the summer and then hovering near $6/GJ through the September to December period.

Events and trends that impacted on Pool prices this year are discussed in the following sections.

1.1.1 KEG Conversion Project

The Edmonton-Calgary 500 kV transmission development involves two phases – first, the conversion of the existing south 240 kV transmission leg (1203L and 1209L) linking Keephills, Ellerslie, and Genesee (KEG), followed by the construction of a new 500 kV line between Genesee and Langdon. One of the main events this year that influenced Pool prices was the KEG Conversion project. This project was deferred from the previous year due to some equipment problems and ultimately was executed from mid March to the end of May, 2008. This project is a prime example of an important transmission-related activity that had a dramatic effect on Pool prices.

During the execution of the KEG Conversion project, significant volumes of base load generation in the KEG area were constrained down and intertie import capacity was reduced. Ultimately, April and May average prices were $135.95/MWh and $103.73/MWh, respectively - high values for these shoulder months. In 2007, April averaged $51.55/MWh and May $48.37/MWh.

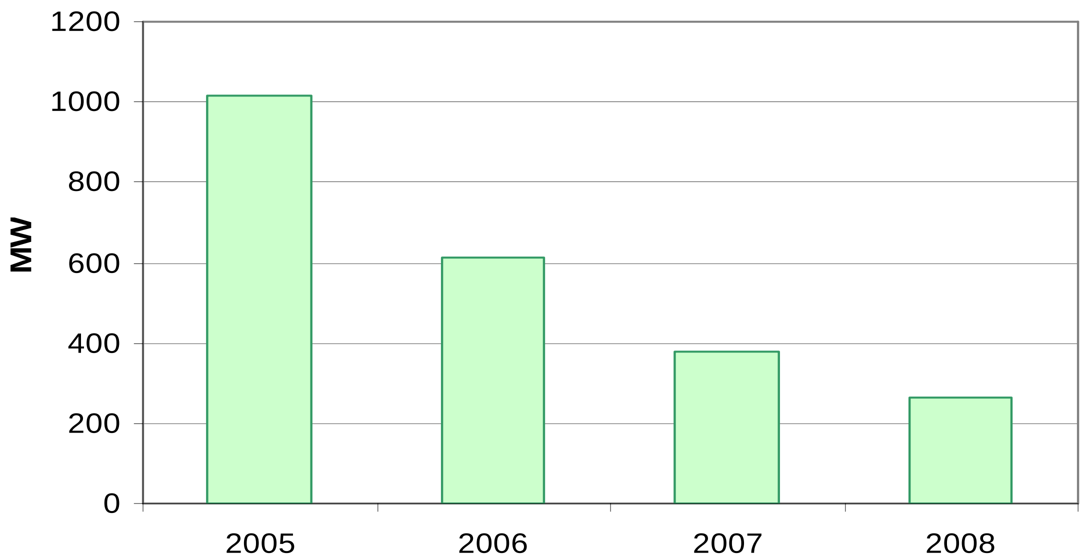
1.1.2 Less Extreme Summer

Summer can produce some extreme prices in the Alberta electricity market usually as a result of high demand, planned maintenance and high derates caused by the hot weather. The two previous years had produced average July prices of $154/MWh (2007) and $128/MWh (2006). The weather in July 2008 was not as hot as those prior years, plus generation availability was better resulting in a lower average price for the month of some $65/MWh.

August was warmer than July and a new record summer peak demand was set on August 18 of 9541 MW, up from 9321 MW set on July 19, 2007. At the time of the new summer peak, the standing record winter peak demand was 9710 MW from January 28, 2008. Subsequently, this past December 15, 2008 the system set a new record winter demand of 9806 MW.

The gap between the summer and winter peak demands continues to narrow in Alberta, driven in part by an increased use of air conditioning systems in domestic households (see Figure i). There is a real prospect that Alberta may soon become a summer peaking system.

Figure i - Winter to Summer Peak Differential (Calendar Year)



1.1.3 Lower Gas Plant Availability in the Fall

The early fall period is one which characteristically has light loads and corresponding softer market prices. In 2008, the system experienced some short-term tightness due to generation outages with corresponding elevated prices. The major contributing factor was maintenance at gas fueled plants. This was unusual as more commonly we have observed elevated prices in response to coal unit outages. Three times in the mid September to early October period the System Controller issued emergency alerts and price was at the cap. For more details, please refer to the Q3/08 report.

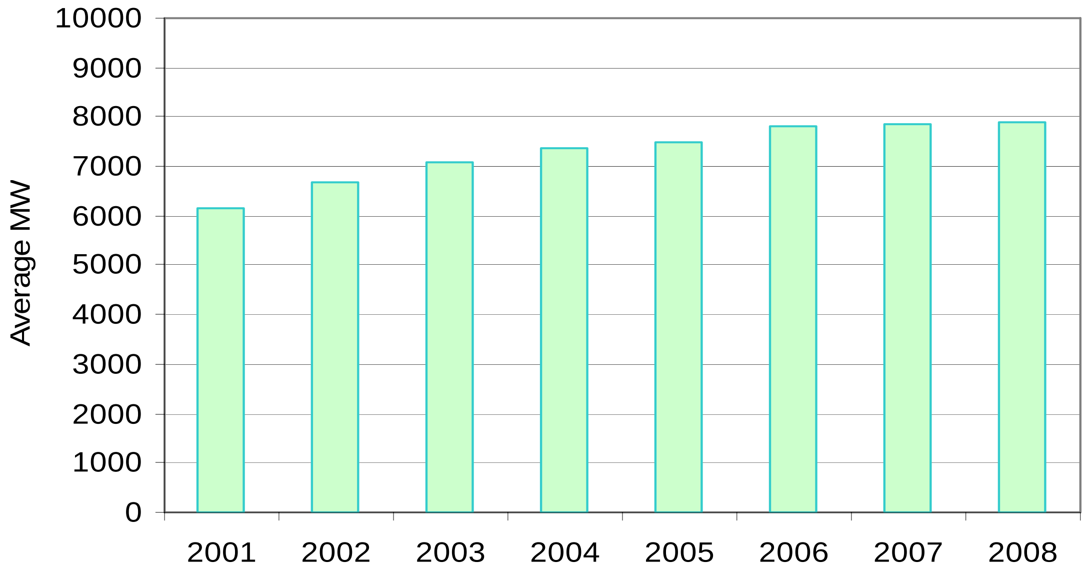
1.1.4 SVC Outage & Cold Weather at Year End

In the latter part of the year an important piece of transmission equipment had to be upgraded. The Static VAR Compensator (SVC) was out of service for over a month and led to a significant increase in the volume of TMR that was required. In turn that led to more MWs of Dispatch Down Service (DDS) to be utilized. At about the time that the SVC came back into service Alberta hit a deep freeze and the load increased in response. The higher than usual mid to late-December loads resulted in some high prices when several unplanned generation outages occurred.

1.1.5 Moderating Load Growth

Interestingly, although the load was high at the end of the year, and peak loads keep setting new records, from a generator's perspective it is the growth of average load that is probably more important. Figure ii shows that growth has essentially flat-lined over the past few years. The general economic downturn that is evident to all of us does not suggest a dramatic upturn is just around the corner.

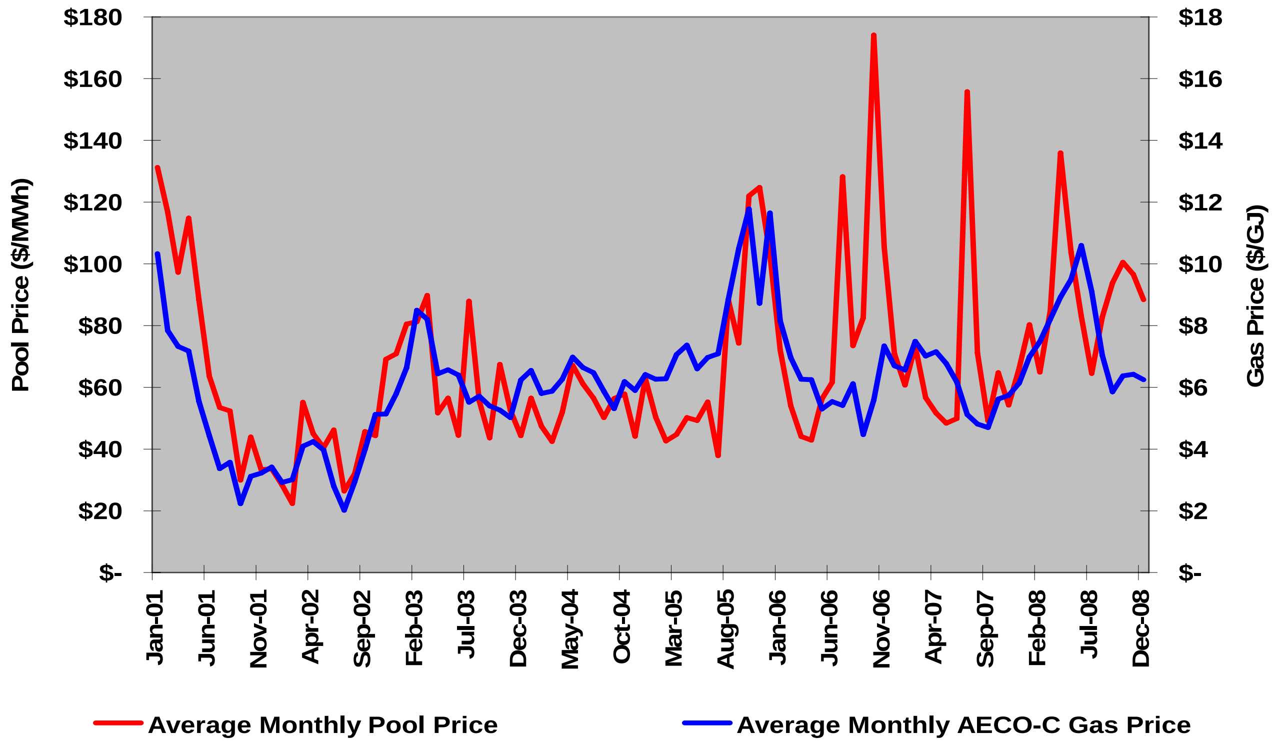
Figure ii - Growth of Average Load



1.1.6 Correlation Between Pool Price and Natural Gas

Although the cost of natural gas is significant for many Alberta generators, the relationship between Pool price and the natural gas price is weaker than in the past. Figure iii shows the relationship for the past 8 years and it is apparent that the degree of correlation has reduced in recent years.

Figure iii - Pool Price and Natural Gas Price Figure



The reasons for the degradation of correlation are difficult to understand. The shares of price setting among the different fuels, although variable from year to year, has not altered substantially in the past five years. It is apparent that other factors are now key drivers of generator offer strategies and therefore Pool prices including:

- Intermittent generation, such as wind;
- Forced outages at base-load plants, especially coal; and,
- Transmission related events such as the KEG Conversion project.

At this point, the MSA does not have a view that the degradation of the correlation of Pool price with natural gas is good or bad, simply that it is a feature of the market at the present time. The MSA will be keeping a close watch on this matter in the future.

1.2 Net Revenue Analysis

The MSA has undertaken directional analysis of the potential profitability of hypothetical new entry on several occasions. The analysis serves as a simple check as to whether 2008 prices provided revenues that, if repeated, would attract new entry to the market. Revenues that repeatedly failed to meet this test would lead to a concern that the market would not attract new investment. Similarly, revenues that are persistently in excess of those required to support new entry without new build occurring would be a signal that disincentives for investment exist.

The hypothetical new entrants that were considered previously were a base-load coal unit, gas-fired combined cycle plant and a combustion turbine unit. In revisiting this work for the purposes of this 2008 year in review, consideration was given to adding two new types: co-generation and wind. We rejected the co-generation option on the basis that each plant is configured to the specific circumstances of the host and there is no 'generic' plant with 'typical' costs and characteristics. Further, power revenues are not the only factor at play in the investment decision. However, new wind farms have been built in Alberta and elsewhere and reasonably consistent price data is available. Thus a wind farm is included in this analysis.

Hence, the hypothetical new entrants under consideration were:

- Coal Unit;
- Combined Cycle Plant;
- Combustion Turbine unit; and,
- Wind Farm

In each case, the assumption was made that the hypothetical new entrant was available for the calendar year 2008, and its existence had no effect on Pool prices. This latter point is clearly open to debate since, particularly in the case of a large coal unit, the notion that Pool prices are unaffected is not correct. However, to adjust the Pool prices for this effect is well beyond the scope of this exercise.

Key cost and operational characteristics of all the units are presented in Table i. This information was updated using public sources and informal discussions with Alberta participants.

Table i - Cost and Key Technical Parameters

Item	Unit	Coal	Combustion Turbine	Wind	Combined Cycle
Capacity	(MW)	450	47	66	250
Availability	(%)	92	94	100	92
Capital Cost	($Million)	1,575	47	112.2	375
Capital Cost/MW	($Million/MW)	3.5	1	1.7	1.5
Annual Fixed Cost	($Million)	30.2	2.68	1.65	15.0
Minimum Output	(MW)	216	0	0	135
Variable O&M	($/MWh)	$1.00	$0.50	0.00	$1.00
Fuel	Type	Coal	Natural Gas	Wind	Natural Gas
Fuel Cost	($/MWh)	$10.00	variable	-	variable
Heat Rate	(GJ/MWh)	-	10	-	8
Losses (2008)	(%)	4.78	4.78	4.78	4.78
Starts	($/start)	-	300	-	-

For each new hypothetical entrant, assumptions were made about typical operation in the market and then simulated on an hourly basis. Generation, costs and revenues were then summed up over the year. Finally, the operating profit was calculated and then compared with the capital cost of the new entrant to provide a measure of its economic viability for 2008.

1.2.1 Coal Unit

The most recent coal unit additions in Alberta have been at existing generating stations. For this analysis, the assumed cost and operating components for the hypothetical new entry are more comparable to a unit being added at an existing site rather than the first unit at a green field site. The latter would be significantly more costly to build without the benefit of shared infrastructure.

The new coal unit has been assumed to run in base load mode except when on outage and no partial loading of the unit was simulated. This ignores the few hours in the year when Pool price briefly dipped below the unit's variable cost and where it might have backed down to its minimum stable generation level. The effect of the outages was mimicked by simply scaling monthly generation parameters by the availability rate.

The simulated generation output for 2008 for the coal unit was 3,637 GWh corresponding to an average of 414 MW and a capacity factor of 92%. With an average Pool price in 2008 of almost $90/MWh the unit generated net revenue of $241 million corresponding to $536,111/MW or about 15.3% of capital cost.

In previous work on net revenue, the MSA has considered a threshold of 15% as a 'build' signal for investors. In the current economic climate, it is difficult to say what the relevant value might be.

Significant uncertainties exist about the effects of climate change on the future operational costs of newly built coal units. Under current Alberta legislation, a new unit has three years to establish a baseline against which future actions are then compared. During those three years there are no emissions charges for the unit. However, the Canadian federal government is developing its own set of rules and the US government is also considering how it can best meet this new challenge. The future then is very uncertain, but for the present purpose no emission costs were assumed in the calculations.

1.2.2 Combined Cycle Plant

The hypothetical new entrant is rated at 250 MW and its operation varies with the cost of natural gas. The plant was assumed to run at a low level of output in all hours and then to ramp up to maximum generation when Pool price exceeded its variable costs. The effect of outages was included in the same manner as for the coal unit.

Observation of the operation of ENMAX's Calgary Energy Centre over a number of years suggests that it is often more economic to turn the unit off for some periods and then to resume generating when prices are more favourable a few hours later. In some cases, there are periods of several days with soft Pool prices when shutting in the plant is the rational thing to do. However these refinements require a more sophisticated simulation model than the one used in this exercise and mean that the net revenues calculated herein are somewhat understated in this regard.

The plant's generation and operating profits for 2008 are presented in Table ii. It is apparent that the plant did not make an operating profit in all months – it lost money in February and July. Clearly these are strong candidates for months in which routine maintenance could have been undertaken or just simply shutting in the plant for a portion of the time. Nonetheless, for the year, the plant made an operating profit of some 11.6% of capital cost.

Although the future environmental uncertainties for a newly built natural gas fired plant are less than for a coal unit, they still exist. This analysis has not attempted to quantify the uncertainty and no cost factors for this have been included for the combined cycle plant (or the combustion turbine unit).

Table ii - Combined Cycle Production and Operating Profits

Month	Total Production (MWh)	Average Hourly Production (MWh)	Average Hourly Production (%)	Monthly Net Revenue($)	Capital Cost (%)
January	130387	175	70%	$2,849,477	0.8%
February	121569	175	70%	-$350,225	-0.1%
March	131233	176	71%	$1,987,049	0.5%
April	141266	196	78%	$8,704,342	2.3%
May	129435	174	70%	$3,615,774	1.0%
June	108891	151	60%	$880,074	0.2%
July	111660	150	60%	-$1,452,343	-0.4%
August	123298	166	66%	$3,287,993	0.9%
September	120106	167	67%	$6,518,292	1.7%
October	131128	176	70%	$6,798,500	1.8%
November	129012	179	72%	$5,786,052	1.5%
December	135360	182	73%	$4,849,372	1.3%
Annual	**1513345**	**172**	**69%**	**$43,474,357**	**11.6%**

1.2.3 Combustion Turbine Unit

A 47 MW single GE LM6000 gas turbine generator set was chosen to represent a typical gas-fired new entrant to the Alberta system suitable for peaking duty. The latest technology may more accurately be represented by GE's new LMS100. However, none are yet operational in Alberta although Epcor is constructing two at its Clover Bar site. LM6000 units are still being built in Alberta (including one last year at the Clover Bar site by Epcor and one at Valley View by ATCO) and are being retained for now as the representative peaking thermal unit in this analysis.

The newest versions of the LM6000 units can ramp to full output in 10 minutes and so the dispatch algorithm was quite simple and the unit was assumed to run at full output whenever Pool price was higher than the variable operating costs. It was assumed that all maintenance could be carried out with no loss of generation.

The unit's generation and operating profits for 2008 are presented in Table iii. It is evident that the LM6000 would have fared very well in 2008, better than the combined cycle plant. A net revenue of 20% was calculated for 2008.

Table iii - Combustion Turbine Production and Operating Profits

Month	Total Production (MWh)	Average Hourly Production (MWh)	Average Hourly Production (%)	Monthly Net Revenue($)	Capital Cost (%)
January	8527	11	24%	$544,417	1.2%
February	6185	9	19%	-$40,700	-0.1%
March	8703	12	25%	$379,973	0.8%
April	12326	17	36%	$1,495,075	3.2%
May	8527	11	24%	$754,032	1.6%
June	6008	8	18%	$798,425	1.7%
July	5213	7	15%	$76,930	0.2%
August	9057	12	26%	$712,454	1.5%
September	9278	13	27%	$1,373,652	2.9%
October	10250	14	29%	$1,316,423	2.8%
November	9189	13	27%	$1,104,894	2.4%
December	12459	17	36%	$882,747	1.9%
Annual	**105723**	**12**	**26%**	**$9,398,323**	**20.0%**

1.2.4 Wind Farm

Alberta now has close to 500 MW of wind capacity in the system with many thousands more in the queue. Clearly, it is appropriate to consider a wind farm as a candidate new entrant. Many wind farms are in the process of being developed here in Alberta and across North America.

The new entrant wind farm is assumed to comprise 22 units at 3 MW each for an installed capacity of 66 MW and to be located in the same general area as the existing wind farms in Alberta. The wind farm was not 'dispatched' but assumed to operate when wind was favourable and take whatever Pool price applied. In this exercise, in each hour the generation from the new wind farm was based on the capacity factor of all existing wind farms in the province. In other words, the new wind farm generated exactly like the average of all the existing wind farms in Alberta. However, as for all the other technologies considered in this analysis, Pool prices were not adjusted to account for the existence of the hypothetical new entrant.

The development of wind farms in Alberta to date has been largely in the southwest of the province and they seemingly experience the same air flows. The hoped for diversity of wind power production across the wind fleet is not yet evident and one of the outcomes is that wind generation tends to 'eat its own lunch' - meaning that increased capacity of wind production is reducing the average Pool price revenue to each wind farm. Wind farm developers are aware of this phenomenon and are seeking development sites with less coincident wind patterns.

The farm's generation and operating profits for 2008 are presented in Table iv. The average received Pool price for the wind farm was $71.54/MWh, well below average Pool price in 2008 ($89.95/MWh). Average annual production was 23MW representing a capacity factor of 35%. Calculated net revenues of 13.4% included the Federal Government's production incentive of $10/MWh. Without the production incentive, the return would be only 11.6% indicating its importance to wind developers. No allowance was included for other revenues that may be had from selling green credits associated with wind power production.

Table iv - Monthly Wind Production and Net Revenue

Month	Total Production (MWh)	Average Hourly Production (MWh)	Average Hourly Production (%)	Monthly Net Revenue($)	Capital Cost (%)
January	25220	34	51%	$1,747,075	1.6%
February	19565	28	43%	$1,184,597	1.1%
March	21545	29	44%	$1,536,680	1.4%
April	19401	27	41%	$2,167,650	1.9%
May	13940	19	28%	$1,192,933	1.1%
June	12093	17	25%	$772,547	0.7%
July	10216	14	21%	$526,869	0.5%
August	13590	18	28%	$802,868	0.7%
September	8764	12	18%	$612,839	0.5%
October	18836	25	38%	$1,424,681	1.3%
November	24121	34	51%	$2,049,937	1.8%
December	17578	24	36%	$1,035,351	0.9%
Annual	**204869**	**23**	**35%**	**$15,054,027**	**13.4%**

1.2.5 Summary of Net Revenue Results

The performances of the various hypothetical new entrants are compared on Table v. Generation capacity factors differ quite markedly amongst them. The base load coal unit has the highest capacity factor at 92% and the LM6000 has the lowest at 26%. All the net revenues are positive on an annual basis – meaning that the revenue from the operating hours was in excess of any fixed and variable costs (O&M and fuel). In fact, the net revenues are well above zero and are generally represent a positive investment signal. The range is 11.6% to 20.0%.

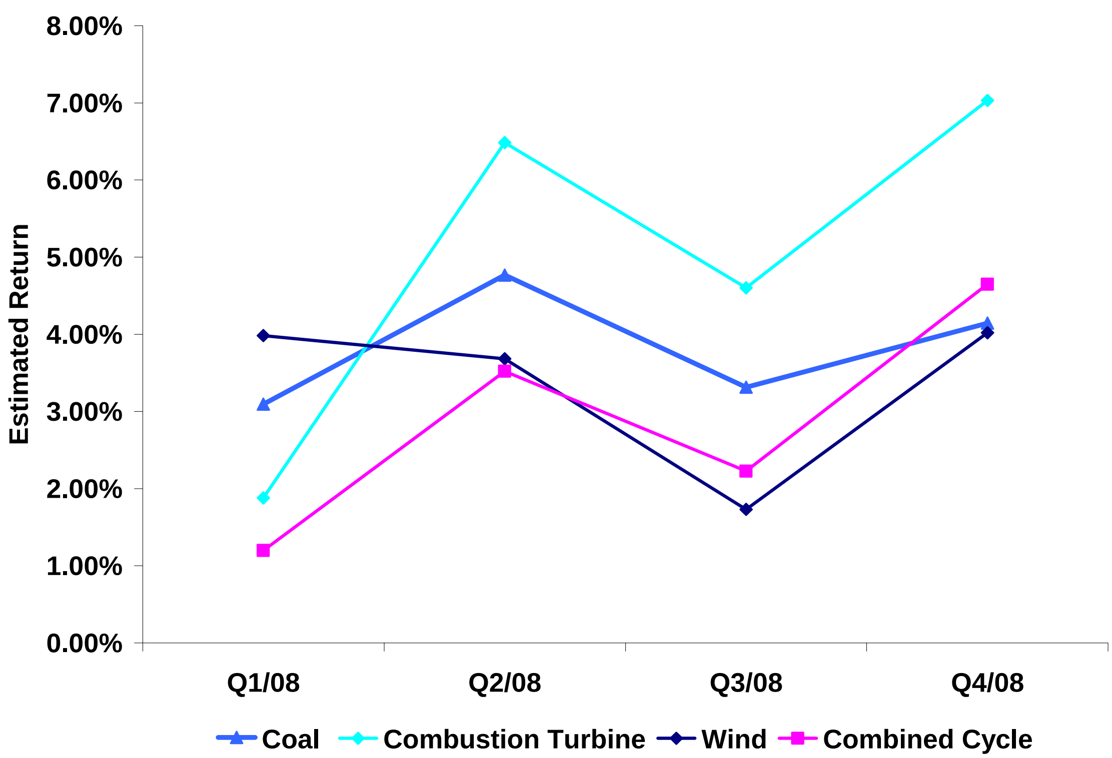
Table v - 2008 Performance by Unit Type

Plant	MCR	Capacity Factor (%)	Capital Cost/MW	Net Revenue/MW	Net Revenue % Capital Cost
Coal	450	92	$3,500,000	$536,111	15.3%
LM6000	47	26	$1,000,000	$199,964	20.0%
Wind	66	35	$1,700,000	$228,091	13.4%
Combined Cycle	250	69	$1,500,000	$173,897	11.6%

The MSA is not privy to the required rate of return for an individual firm to make the decision to build a project. The recent economic turmoil across the world may well have impacted the ability of potential investors to secure credit. However net revenues in the range shown on Table v would seem to be attractive. The MSA would be pleased to hear from market participants on this matter.

Figure iv shows the quarterly net revenues for each technology. Notably, the values are positive in all cases and all quarters.

Figure iv - Net Revenue Analysis by Quarter



Having observed that the data for 2008 seems to provide a build signal, it is interesting to see what new projects are expected to be built in the near term. The AESO publishes Long Term Adequacy Metrics on a regular basis to provide information to the market at large on the reliability of the system over the next few years. Included is information on new projects in various stages of development and announced retirements. Table vi was constructed using information from the most recent update in February, 2009.

Table vi - Long Term Adequacy Metrics

In Service Date by end of 2010	Capacity (MW)
Under Construction	858
Regulatory Approval	310
Announced	1083
Retirements	-525
Net Additions by end of 2010	1726

Recognizing the decline in load growth demonstrated in Figure ii, the anticipated net additions over the next two years of some 1726 MW seem to be the expected response to the price signal, and adequate to support both the market and reliability.

1.3 Analysis of the Effects of Quick Hits

The Alberta Electric System Operator (AESO) implemented a major package of rule changes at the end of 2007, collectively known as the "Quick Hits".

The "Quick Hits" were comprised of four main areas:

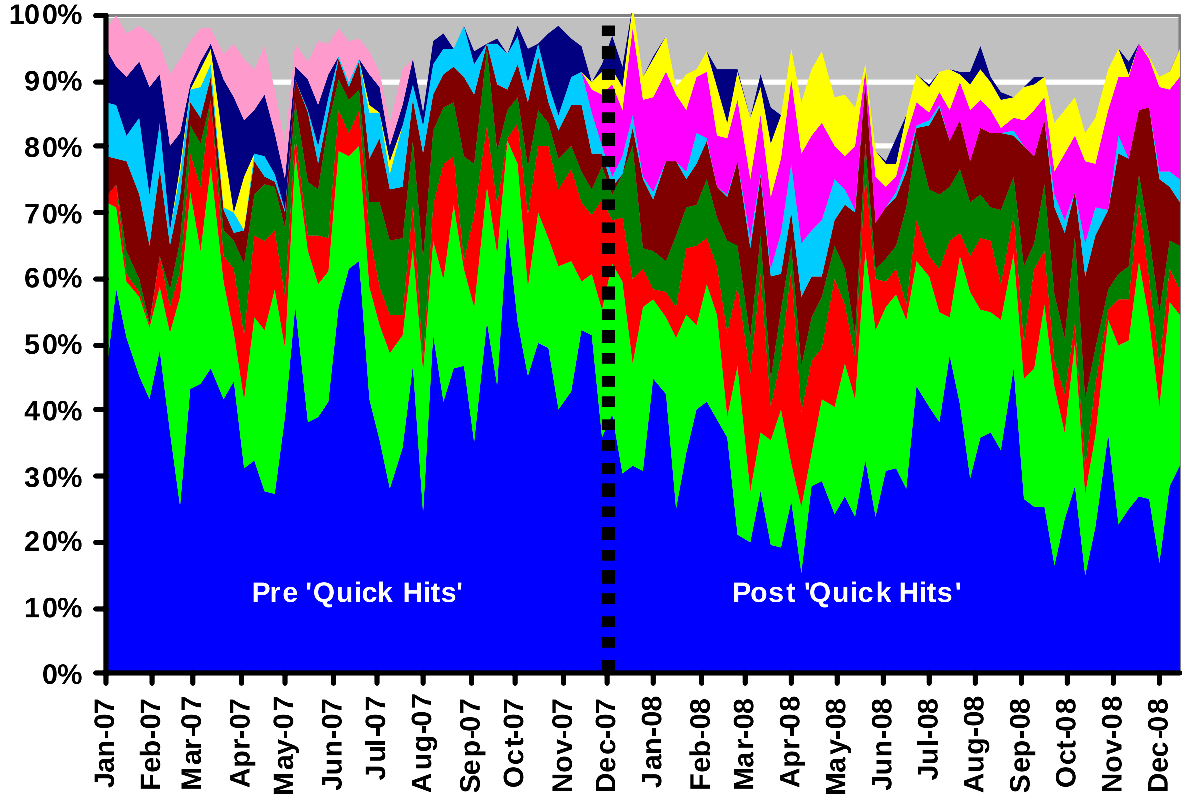
- Merit Order Stabilizers;
- Reconstitution of Pool price for Transmission Must Run (TMR) Energy;
- Payments to Suppliers on the Margin; and,
- Treatment of Imports/Exports.

1.3.1 Merit Order Stabilizers

The new rules featured obligations for generators such that they "must offer" energy and "must comply" with dispatches. In addition the rule changes allowed greater flexibility to change offers two hours prior to the hour to which those offers applied (i.e. before T-2) and less flexibility after T-2. The MSA had expected these rules to have a fundamental impact on offer behaviour. Volatility, price dynamics and the impact on the merit order were the focus of our Q1/08 report. At that time, we concluded there had been relatively little impact from the new rules. This still appears to be the case and while changes have occurred they have been more subtle than expected.

One noticeable impact reported in the Q1/08 report was the change in distribution in price setting share by submitting participant – with price setting becoming less concentrated. In looking at 2008 as a whole, the same conclusion can be reached (see Figure v). Post-Quick Hits some new price setters have emerged that previously adopted a price taking (passively offering low in the merit order) or price chasing (offering low in the merit order using energy restatements) strategies. Some participants with small but significant pre-Quick Hits price setting shares now have reduced their shares as a result of participation in the DDS market.

Figure v - Price Setting by Submitting Participant - Pre v. Post Quick Hits



1.3.2 Reconstitution of Pool price for Transmission Must Run (TMR) Energy through Dispatch Down Service (DDS)

In some areas of the province transmission constraints result in additional energy being needed in a local area. In order to deal with these constraints the AESO dispatches generators for Transmission Must Run (TMR). Since these dispatches occur outside the normal order of economic merit they tend to have a suppressing impact on Pool price. The "Quick Hits" rules included the introduction of a Dispatch Down Service (DDS) designed to offset the impact of TMR by reconstituting the Pool price.

All generators may offer DDS, with the offer 'price' being a discount to Pool price, similar to the active Operating Reserves market. Offers are selected from those eligible on the basis of price (largest discount to Pool price first).[1] DDS offers are selected to offset the difference between MW currently dispatched for

[1] The eligibility criteria for DDS at set out in ISO rule 6.3.6.1

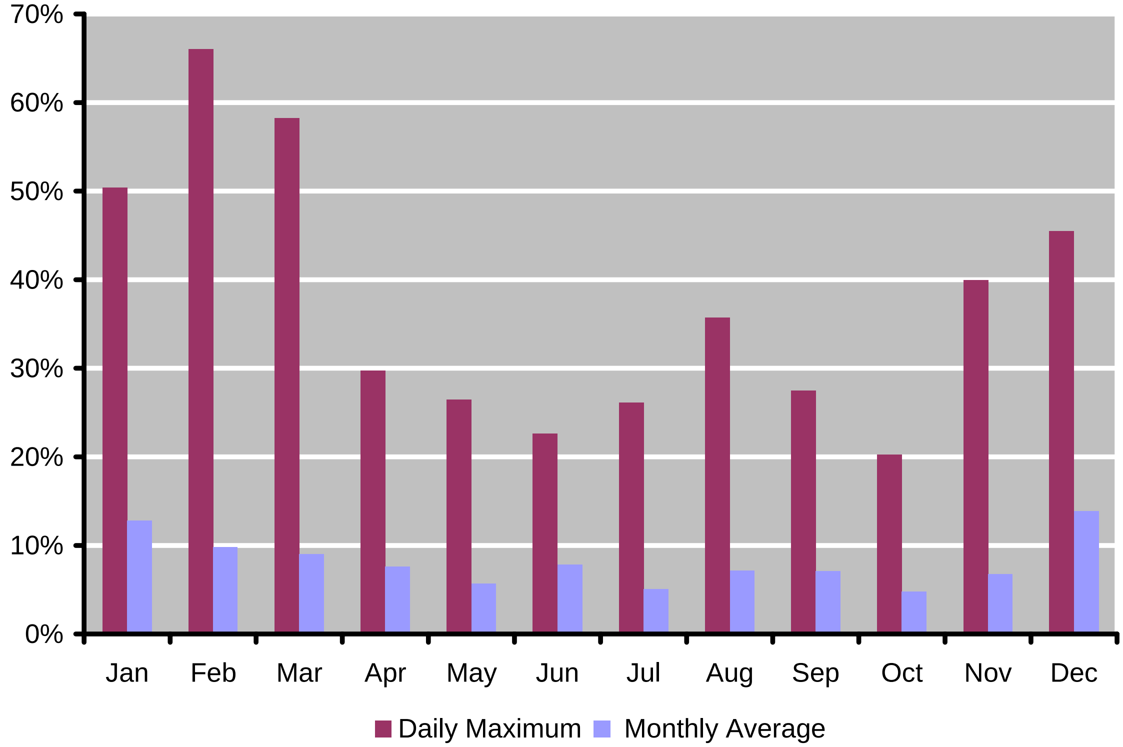
TMR and constrained down generation (e.g. generation constrained down by transmission constraints). Further DDS is only selected if the current SMP is below an administratively set reference price. DDS costs are recovered from other generators (see Table 6 in Appendix D for information on DDS costs during 2008).

In July 2008 the MSA published a stand-alone report examining the effectiveness of DDS with additional analysis reported in Q3/08 report. Throughout 2008, the DDS market has been successful in attracting more eligible DDS offers than required to reconstitute the price (see Figure 24 in Appendix D). However, the MSA continues to believe that DDS is only being partially successful in reconstituting Pool price. As noted in the July 2008 report, some generators who would likely not have chosen to run at the prevailing Pool price make offers to do so with the intention of being dispatched for DDS.

The MSA has also expressed its concern about price "stickiness" around the reference price. This is problematic if the existence of the reference price becomes a driver of offer behaviour and that price is no longer truly reflective of fundamentals. Figure vi shows the percentage of time in each month that the system marginal price (SMP) has been within $1/MWh of the reference price. In some months this has averaged over 10% of the time and on some days much more. In the most extreme case, on February 1, 2008 the price was set within $1/MWh of the reference price 66% of the time.

The MSA continues to watch the impact of the reference price on offer dynamics with interest. In earlier 2009, with natural gas prices continuing to fall, the reference price is expected to approach $50 (substantially lower than $138/MWh reached in July, 2008). The MSA is monitoring to see what impact this will have, particularly on generators with portfolios skewed towards non-gas generation.

Figure vi - Average and Maximum Time SMP Lies Within $1/MWh of Reference Price



1.3.3 Payments to Suppliers on the Margin

The "Quick Hits" featured payments to suppliers on the margin. The payment was aimed at addressing a mismatch between dispatch and settlement. In the Alberta market units are dispatched during an hour with the last unit dispatched (highest price) setting system marginal price. Settlement is performed on the hourly Pool price (the time weighted average of the SMP's in the hour). In some hours, this mismatch results in a generator receiving considerably less than its offer price and this served as a disincentive for generators to respond to dispatches, particularly if they believed price had risen only temporarily. A better match between dispatch and settlement could be achieved by moving to more frequent settlement periods (e.g. 5 or 15 minutes rather than one hour). This mismatch was seen as leading to a poorer quality price signal and one that encouraged price chasing behaviour (generating in accordance with expected Pool price rather than dispatch signals).

Changes to settlement periods would require a significant investment in new systems – instead, a "Quick Hit" was to provide generators dispatched with offers above the hourly Pool price with an additional payment.[2] Additional payments

[2] The June 6, 2005 paper entitled *Alberta's Market Policy Framework: Competitive - Reliable – Sustainable* recommended the ISO seeks ways to address a more efficient and stable merit order, limit incentives for

are made where the generator's hourly production exceeds the MW that would have been dispatched at Pool price[3] limiting the incentive for price chasing by the marginal unit and ensuring generators were not financially disadvantaged due to Pool price determination.

Table vii shows the monthly and yearly totals made to suppliers on the margin. Overall, the payments made to suppliers on the margin during 2008 was relatively small at $3.4 million. In 2008, over 12,000 payments to suppliers on the margin were made. 77% of payments were under $100. The size of the payments is typically very small since after receiving a dispatch there is delay between when a generating unit receives the dispatch instruction and the time at which additional MW's are produced. In cases where price is volatile, a generating unit may receive a dispatch to a higher level only to be dispatched back to the previous level a few minutes later, which in turn limits the size of the payment that may be received.

On average, the payments made to sellers who also provided TMR in the same hour were more than $1000. The MSA has estimated that approximately 1/3 of the total $3.4m paid to suppliers on the margin went to TMR providers. TMR providers tend to receive higher payments than other generators (about 5 times as much on average) since they do not experience a delay between responding to the dispatch and producing MW's, instead upon their offer price being reached they switch from providing energy for TMR services to providing in-merit energy to the market.

The MSA does not believe that the size of the payments to TMR providers or the disparity between this and the payments received by other generators was widely anticipated at the time the rules were introduced.

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price chasing and reduce the impact of price chasing. Payments to suppliers on the margin was one option suggested for achieving this.

[3] See ISO rule 8.1.2 for further details.

Table vii - Estimated Payments to Suppliers on the Margin

Month	Total Payment to all providers	Estimated payment to TMR providers	Number of payments to all providers	Average payment to all providers	Number of payments to TMR providers	Average Payment to TMR Providers
Jan-08	$268,888	$87,458	1,261	$213	77	$1,136
Feb-08	$89,021	$15,765	1,014	$88	34	$464
Mar-08	$259,827	$61,741	876	$297	61	$1,012
Apr-08	$424,744	$99,891	1,066	$398	81	$1,233
May-08	$216,694	$38,684	1,045	$207	59	$656
Jun-08	$238,305	$111,982	912	$261	90	$1,244
Jul-08	$193,198	$67,998	1,027	$188	61	$1,115
Aug-08	$233,458	$50,227	1,046	$223	54	$930
Sep-08	$406,418	$174,106	1,174	$346	134	$1,299
Oct-08	$585,626	$216,165	1,054	$556	178	$1,214
Nov-08	$216,968	$67,963	1,080	$201	113	$601
Dec-08	$311,629	$124,613	1,119	$278	136	$916
Total	**$3,444,778**	**$1,116,594**	**12,674**	**$272**	**1078**	**$1,036**

1.3.4 Treatment of Imports/Exports

Although the source of much discussion during the formulation of the "Quick Hits" rules, little has changed for importers and exporters other than the inability to change their offers after T-2. This is a potential concern due to the mismatch between requirement to offer at T-2 in Alberta and a one-hour ahead market in Mid-C (the source [destination] of significant imports [exports] for the Alberta market).

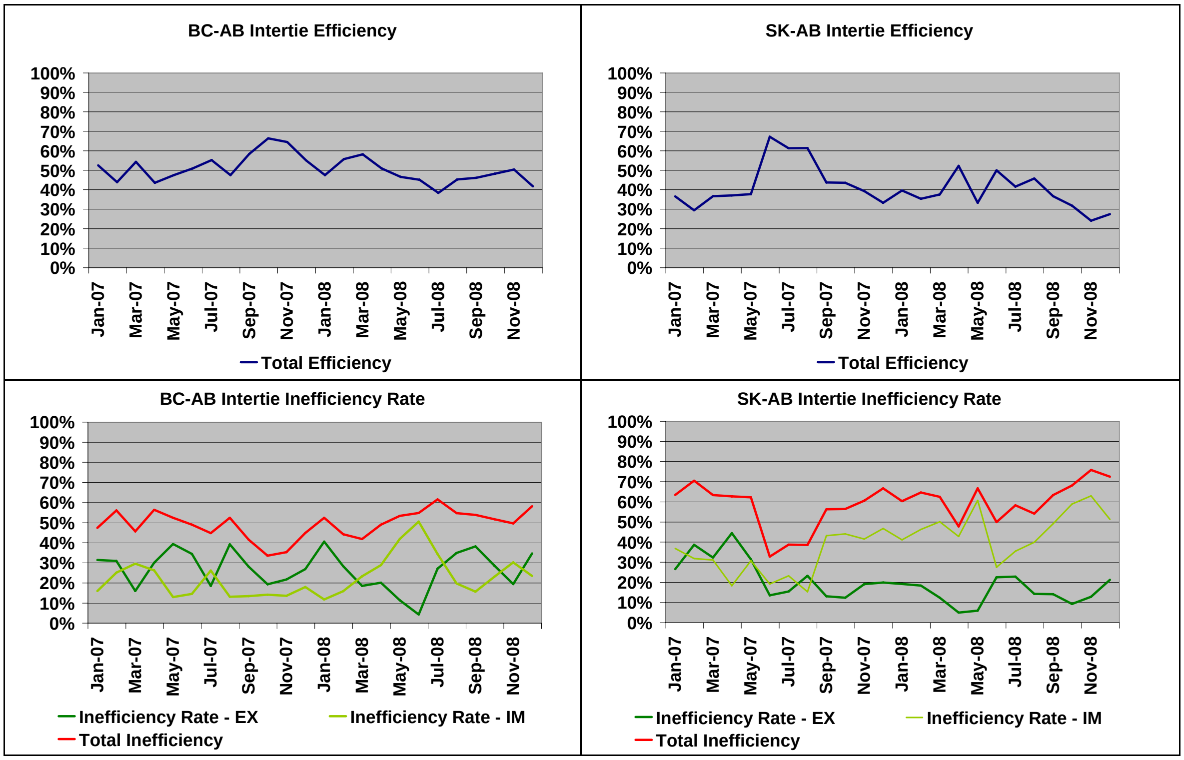
In its previous work on intertie efficiency, the following definition was developed and adopted:

In a given hour, an intertie is efficient when no arbitrage opportunity exists. That is, on that intertie no energy can profitably be moved from one market to another.

The actual calculation involves checking each hour in each direction whether an arbitrage opportunity exists. If one exists in either direction then the intertie is deemed to be inefficient in that hour. Note that this definition means that when the intertie is down on maintenance it is deemed efficient. The definition works best when longer periods of time are considered and the percentage of efficient hours can be calculated.

The MSA continues to monitor efficiency on the interties and Figure vii shows the level of efficiency is slightly lower overall in 2008, but basically comparable with the pre-Quick Hits era.

Figure vii - Efficiency of Use of the Interties, 2008



1.3.5 Other Impacts related to the "Quick Hits"

Implementation of the "Quick Hits" on December 3, 2007 was later than originally anticipated due to information technology stability issues, specifically with the dispatch tool (DT) and the Automated Dispatch and Management System interface (ADAMS).[4] After implementation a number of issues have persisted. In the MSA's Q2/08 report it was noted that a number of Pool price errors had occurred. Since that time, these errors have largely been eliminated. The MSA commends the AESO on its improved communication protocols and the speed with which issues are resolved. Some IT related problems do remain. The MSA has noted a small number of occasions where DDS has been dispatched incorrectly at prices in excess of the reference price. These problems have been short lived and the MSA understands they are due to the DT recalculating the appropriate dispatches as the reference price is crossed. The MSA also understands the same problem has, on occasion, resulted in some market participants receiving multiple and conflicting dispatches within a very short period of time. Such problems are likely to persist until the AESO completes work on a new dispatch tool in 2009.

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[4] See http://www.aeso.ca/downloads/QHDelaysLetterMS-ITMay152007.pdf for further details.

2 FORWARD MARKET

In 2008, the amended Electric Utilities Act broadened the definition of "market participant" to include brokers that facilitate forward financial transactions. As a result, the MSA expanded its market monitoring into the Over-the-Counter (OTC) forward market. Previously, the MSA had regular access to transaction data from the electronic anonymous Natural Gas Exchange (NGX) but not from the brokers.

The MSA wishes to thank the OTC brokers and NGX for their cooperation in providing the data. Brokers facilitating trades involving the Alberta market range in size of operation and some only execute a few trades a month. The MSA has taken steps to obtain all the OTC data from all the brokers to ensure that none are disadvantaged.

2.1 Why is the MSA Interested in the Forward Market?

The MSA is of the view that forward market monitoring is an integral part of overall market monitoring because of important linkages between the forward market and the spot markets:

- The forward market offers a platform where participants with physical positions are able to mitigate risks using financial instruments;
- Different levels of forward hedging of physical assets may affect generators' offer and import/export behaviours to the physical spot market;
- A retailer's exposure to the forward market may impact retail pricing; and,
- Potential new market entrants often 'test the waters' in the forward market in order to acquire market knowledge via financial trading, before making an investment decision.

Likewise, the physical market also impacts the forward market:

- The price setting mechanism of the retail RRO products may affect forward trading volumes and prices; and,
- Information regarding the physical delivery in the spot market may influence forward prices.

A liquid and robust forward market is a crucial component of a fair, efficient and openly competitive electricity market. It achieves this by providing market participants a platform to manage risks and incenting them to use assets to generate electricity and meet demand when the market spot price justifies the dispatch cost of the asset. The existence of a liquid and robust forward market is also dependant on a well functioning physical market. One of the most important jobs for the MSA is to oversee the wholesale spot market to help provide the confidence that is needed for trading activity to flourish.

2.2 The Forward Market Structure

Figure viii illustrates the relationship between the financial forward market and the physical market. In Alberta, activities occurring in the forward market are facilitated by two platforms: the Natural Gas Exchange (NGX) and the Over-the-Counter (OTC) markets. Most OTC activities are carried out through brokers, although two parties may also transact directly. At the present, the MSA's monitoring efforts are focused on the transactions facilitated by NGX and the brokers.

The participants in the forward market include generators, retailers, marketers and financial intermediaries. They typically trade financial swaps that are settled based on the difference between the Alberta spot price (Pool price) and the agreed fixed price.

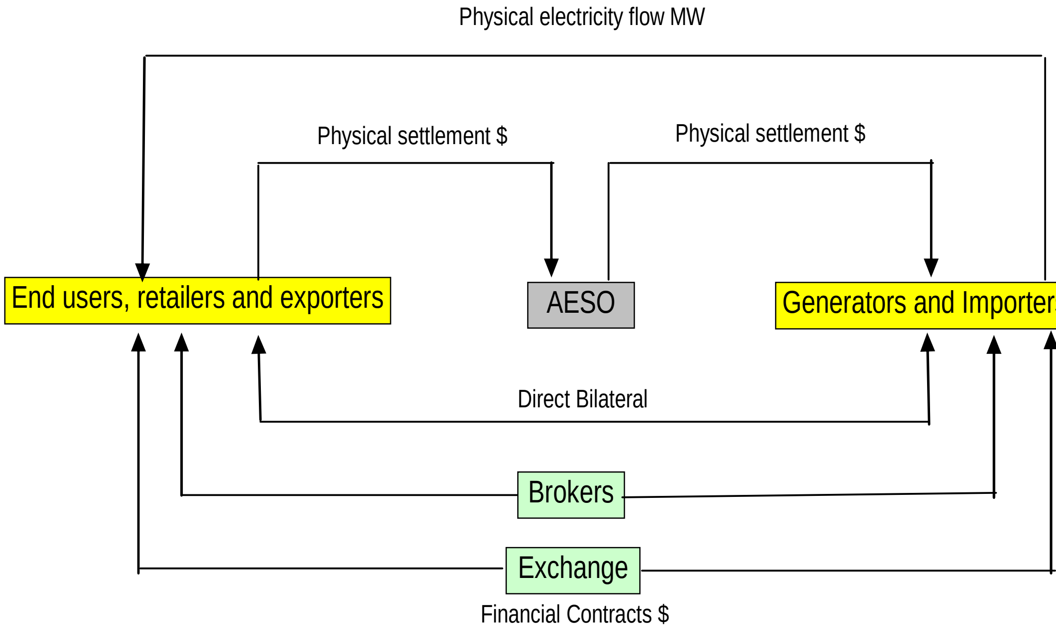
The commonly traded financial swaps include:

- Flat;
- Peak;
- Off Peak;
- Extended Peak;
- Super Peak; and,
- Extended Off Peak.

The most frequently traded contract terms include:

- Daily (including the same day);
- Monthly (including the balance of month);
- Quarterly; and,
- Calendar Year.

Figure viii - Relationship between Forward Financial Market and the Wholesale Physical Market

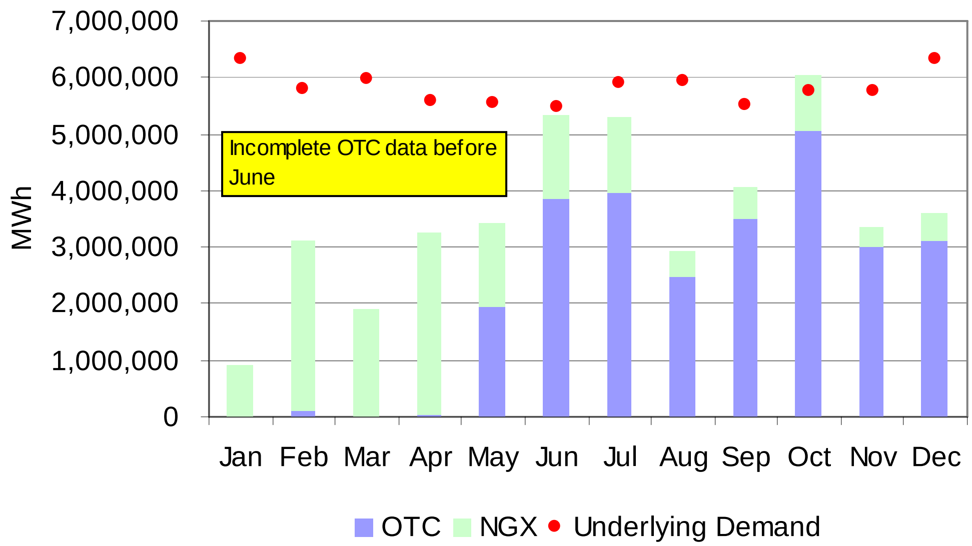


2.3 Trading Volumes[5] and Participation

In 2008, over 16,000,000 MWh of financial contracts were traded on NGX and between June and December[6] close to 25,000,000 MWh transacted on OTC. Figure ix depicts the monthly trading volumes in the forward market.

[5] Trading volumes only include one side of the transactions.
[6] OTC data before June 2008 were not complete.

Figure ix - Monthly Trade Volumes in the Forward Market

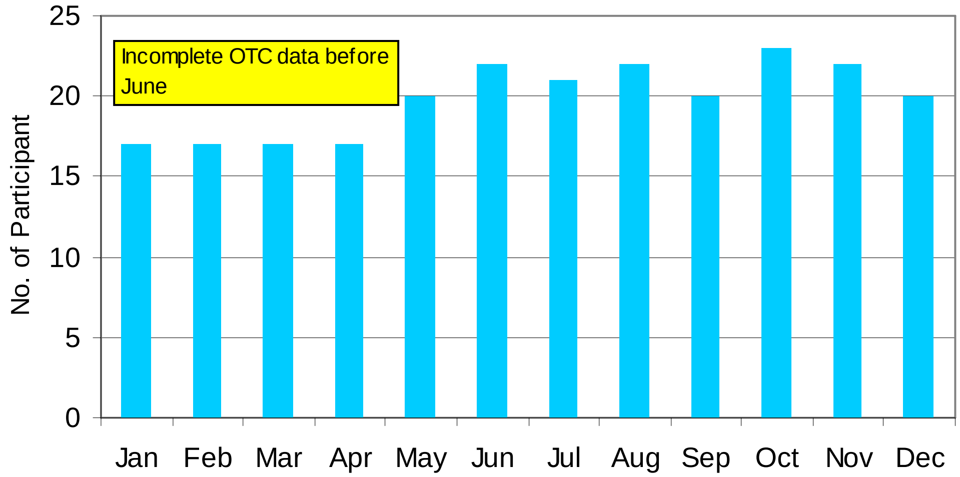


The overall trading volumes of June through December were about 75% of the underlying demand. The underlying demand is simply the volume of physical flow of energy in real time. The volume of trading relative to underlying demand is well below the levels of more mature electricity markets like Mid C and Australia. With enhanced access to forward market data, the MSA is keen to see a general upward trend in the trade volume. Even at current levels, trading volumes appear to be higher than anecdotally reported to MSA several years ago. The MSA is aware that some unknown amount of additional bilateral trading also is occurring in the Alberta market in addition to that reported herein.

One slightly worrying observation is that the trade volumes dropped off quite severely in November and December. It is not clear if that is an effect of the general credit crisis or a seasonal effect. At the time of writing, trading volumes have recovered as demonstrated by 4,000,000 MWh in January and 6,200,000 MWh in February.

Typically, at least 15 different participants traded the forwards each month last year, and generally close to 20 once more OTC data became available. Note that many participants trade on both platforms. Figure x shows the number of participants who traded on the forward market by month. Although some participants were impacted by the financial crisis and credit tightness, all but one remained in the market as of the end of 2008.

Figure x - Number of Participants in the Forward Market



2.4 Contract Term Structure

The terms of the forward contracts traded in 2008 included daily, monthly, quarterly and calendar year. Figure xi depicts the percentages of trading volumes of different contract terms and Figure xii shows the same information except by number of transactions. Note that the trade data is not complete throughout the year and some caution is needed in interpreting the results.

Figure xi - Percentage of Trading Volume by Term

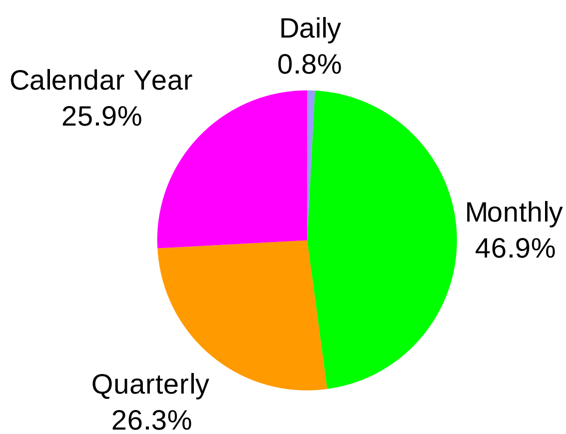
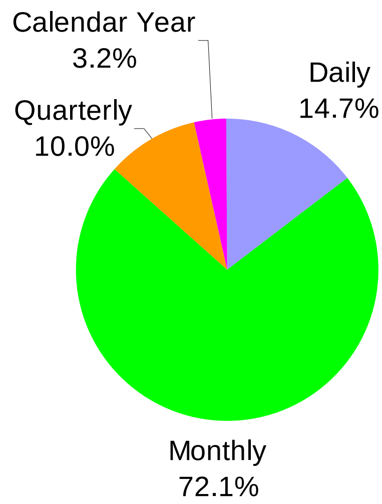


Figure xii - Percentage of Transactions by Term



The trading of monthly contracts is highest both in terms of volume and frequency. Trading of the monthly contract is clearly a dominant feature of the forward market. Most participants who trade forward, will trade the month contract. One reason for the active trading of the monthly contracts was that the monthly contracts are typically traded closer to delivery than the quarterly and calendar year contracts. Therefore more market information is available to prompt the participants to change their views and to adjust their positions via trading. The other reason is that the volume exposure to price volatility is limited due to the limited amount of hours in a month. In addition, some of the RRO regulated rate providers are incented to post bids and offers during the RRO procurement window[7] on NGX which has increased the liquidity of the monthly contracts.

The daily contract is an effective instrument and final opportunity for participants to hedge unexpected risks in the spot market, and its trading represents about 15% of all transactions.

Although less actively traded than the monthly contracts, the quarterly contracts were more liquid than the calendar year contracts. This is because given the contract size, the calendar year contracts have the largest volume exposure to price volatility[8], therefore entail higher risks. Also, calendar year contracts can

[7] The RRO procurement window is between 45 calendar days and 6 business days before the delivery month.

[8] For example, for a contract size of 10 MW, a January 2009 flat power contract has a volume of 7440 MWh but a calendar year 2009 flat power contract has a volume of 87600 MWh.

tie up available credit capacity limiting a trader's ability to make additional transactions. Credit management using netting agreements with counterparties mitigates some of this concern.

2.5 Market Share of Forward Trading Volume by Participant

A total of 25 participants traded in the forward market in 2008. The top 5 participants consisted of generators and financial intermediaries, and traded slightly over half of the volumes. Compared with the physical market, the forward market is less concentrated in trading volumes (Figure xiii).

Figure xiii - Share of the Trade Volumes by Participants

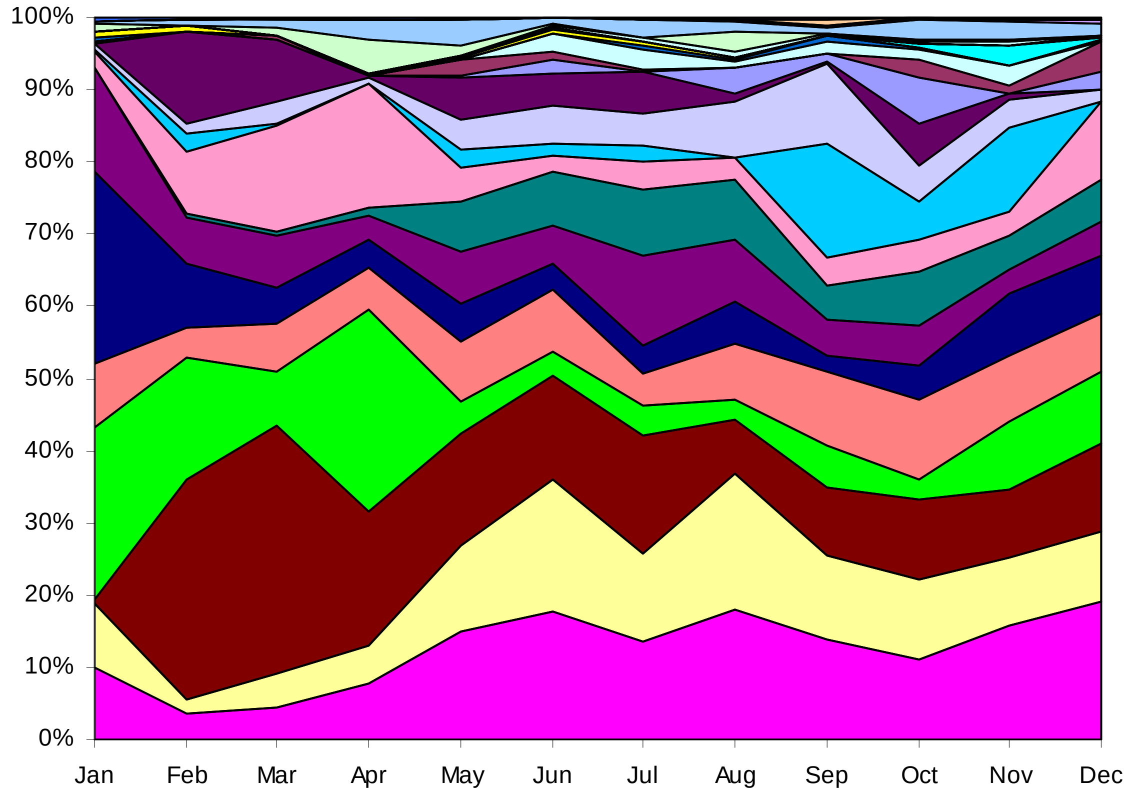
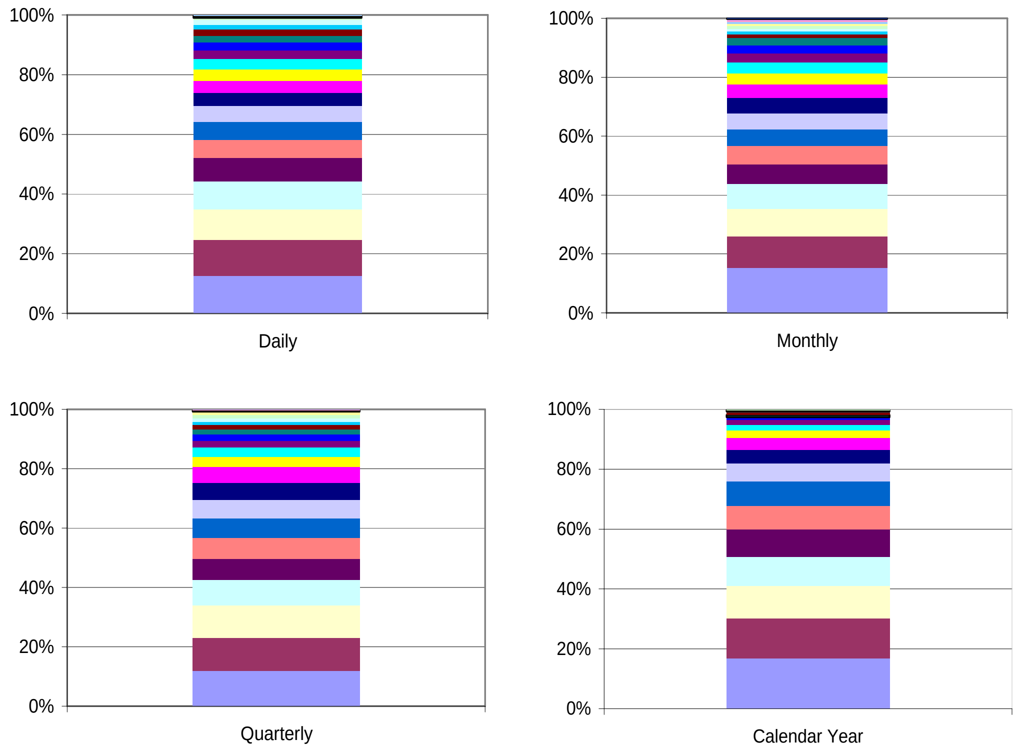


Figure xiv shows the market shares of the various term products. Note that, for the purposes of disguise, the colours of Figure xiii do not correspond with those in Figure xiv. Further, within Figure xiv, the colours across the terms do not correspond with the same participant. Figure xiv shows both a reasonable number of participants and lack of concentration of market shares for all four terms. Market concentration can be measured by the Herfindahl-Hirschman Index (HHI) – the sum of squares of each participant's market share in percent. Table viii shows that the highest participation rates were in monthly and quarterly and all the HHI values were satisfactorily low.

Table viii - Number of Participants and HHI in the Forward Market

Contract Term	No. of Participant	HHI
Daily	22	753
Monthly	25	756
Quarterly	23	744
Calendar Year	19	972

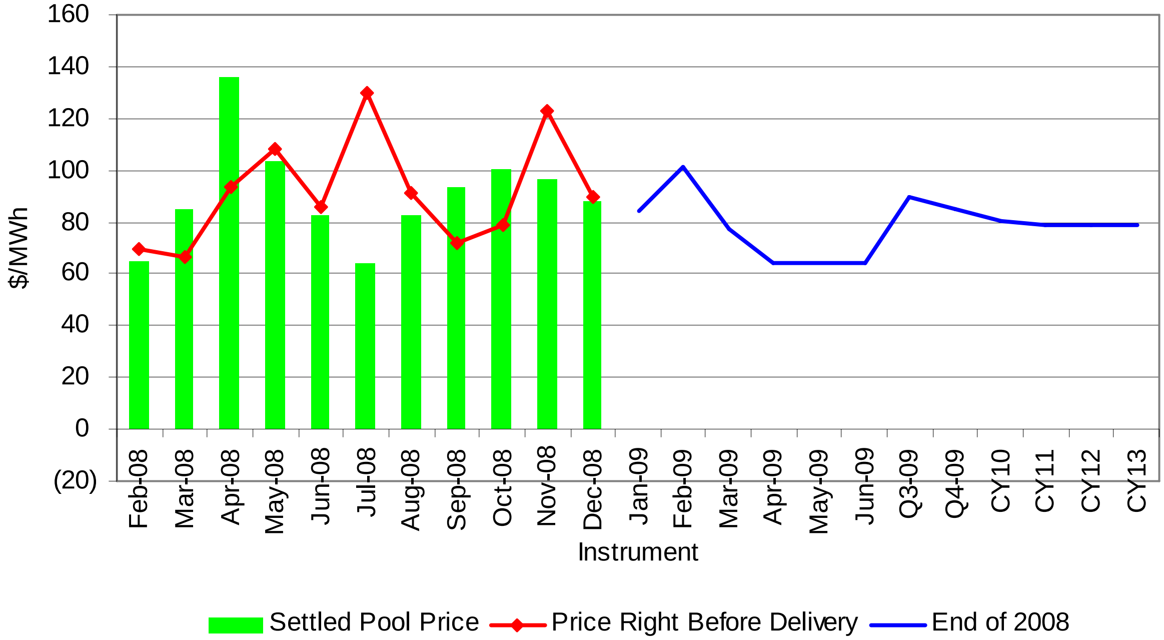
Figure xiv - Market Share of Trade Volumes by Term and by Participant



2.6 The Forward Price

The forward price reflects the market expectation of the spot price. To a large degree the changes in forward price were driven by market information about the spot market. The forward price of the near term contracts is typically more volatile than the longer term contracts as more information is available to the market when it approaches delivery. Since the spot market is subject to unexpected or less predictable events, such as forced outages, changes in wind generation and changes in the flows on the interties etc., it is common to observe discrepancies between the forward and the actual spot prices (Figure xv).

Figure xv - The Forward Price



The prices of the longer term contracts are typically more correlated with forward natural gas prices than are the shorter term contracts. This is because when gas units are often at the margin, the forward gas prices are the most prominent and transparent market information when trading is far ahead of the delivery. The relationship between power and gas prices is also strengthened by participants using natural gas to hedge their electricity positions, e.g. trading heat rates instead of outright power.

Other factors, such as knowledge of new capacity additions, planned outages and demand forecast may also cause the price of longer term contracts to move. Of note is that at the end of 2008, there was a backwardation in the forward calendar year heat rates (negative slope) likely reflecting the market view of the possible increased supply cushion in the next a few years.

3 FEATURED RETAIL MARKET DEVELOPMENTS

3.1 Retail Market Metrics

The MSA published a report on retail electricity and natural gas in February, 2009. Accordingly, this report will only briefly comment on the retail market metrics. For more detail, the reader is referred to the February, 2009 report: (http://www.albertamsa.ca/files/Public_Retail_Report_021309(1).pdf).

The following comments are offered on the figures of Appendix E:

- The residential market shares in electricity (Figure 27, Appendix E) show Retailer C has substantially increased its share of the mass market competitive contracts from about 5% at the end of 2007 to about 8% at the end of 2008;

- Retailer A in the Small Commercial/Industrial category has increased its market share to 24% at the end of 2008 (Figure 28, Appendix E); and,
- In the large non-RRO category, since mid-2007 the ‘Other’ category of retailers has shrunk from 20% to 6%, largely taken up by Retailer A growing from 23% to 37% over the same period (Figure 29, Appendix E).

3.2 Code of Conduct Regulation

As part of its mandate under the Alberta Utilities Commission Act (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, in furtherance of retail competition. The Code governs the relationships between owners of electric distribution systems and their affiliated retailers, as well as dealings with non-affiliated retailers, customers and customer information.

The Code contemplates that owners and affiliated retailers will undergo a compliance audit on an annual basis, 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 2008, a total of eight market participants (owners/affiliated retailers) were audited. The specific period being tested was July 1, 2007 through June 30, 2008, inclusive (as in previous audits, the test period was chosen to avoid carrying out the audits during the first quarter of the calendar year - a time which tends to be very busy in relation to year end financial and other audits).

The testing focused on those sections of the Code which address the following matters: adherence to compliance plans, accuracy of compliance reporting and adherence to the Code in relation to customer interactions. The MSA also looked into issues brought to its attention through regular Code reporting or previous audit(s).

In order to actively test how customer interactions were being handled, random call centre (‘mystery shopper’) testing was carried out in Q2, 2008. The balance of the audit testing plan was carried out through field visits between August and October, 2008. Draft audit findings were then shared and discussed 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. Greater detail can be found in the related Notice posted on the MSA website December 19, 2008 (see www.albertamsa.ca/files/Notice_-_Code_of_Conduct_Testing_2008.pdf).

3.3 Possible Changes to Code Regulation(s)

The Alberta Department of Energy (DOE) has commenced a stakeholder process to discuss possible changes to the electricity and gas Code regulations, as well as other enactments. Any related changes to the Code are currently anticipated to occur in 2010. Accordingly, the MSA will consider and plan Code testing for 2009 per the usual course.

4 FEATURED OPERATING RESERVES (OR) MARKET DEVELOPMENTS

4.1 OR Redesign Process

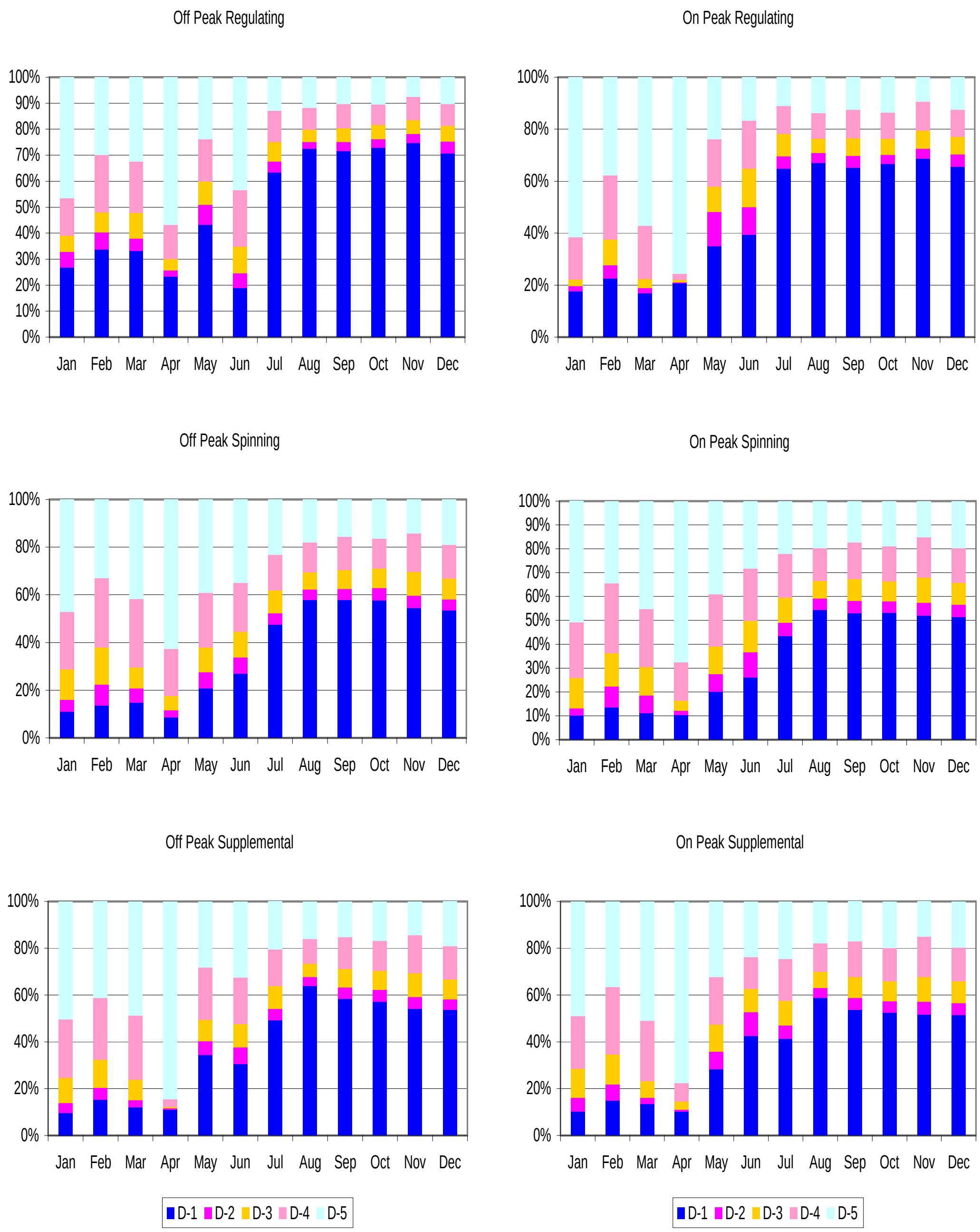
Throughout 2008, the AESO consulted with stakeholders on a redesign of the operating reserves market. The main features of the redesign under discussion are less active participation by the AESO in the market in terms of pricing and the timing of procurement and the implementation of a more transparent and less complicated market to encourage participation. Specifically, the following changes are contemplated:

- Removal of term trading and consolidation of the trading of the active and stand-by products from five days (D-5 through D-1) to just one trading day (D-1);
- Only bid volumes to be set by AESO, not bid prices;
- Clearing price to be set in the active reserves by the marginal seller, similar to the energy market;
- Sellers of standby reserves will compete on premium with an activation price set in the active reserve market; and,
- Procurement of all OR volumes on NGX.

The key to the success of the new design is the ability to attract sufficient sellers to the market for a one-shot auction on (D-1). During the year, the AESO tested this hypothesis within the existing market design framework and modified its procurement. Starting in the middle of the year, the AESO consistently procured a larger portion on the (D-1) trading day rather than on earlier days of (D-2) through (D-5).

Soon after that, AESO set stable bid prices at levels that were expected to incent all the providers to compete. Figure xvi demonstrates the increased portion of procurement at (D-1) across all active reserve products in the second half of 2008.

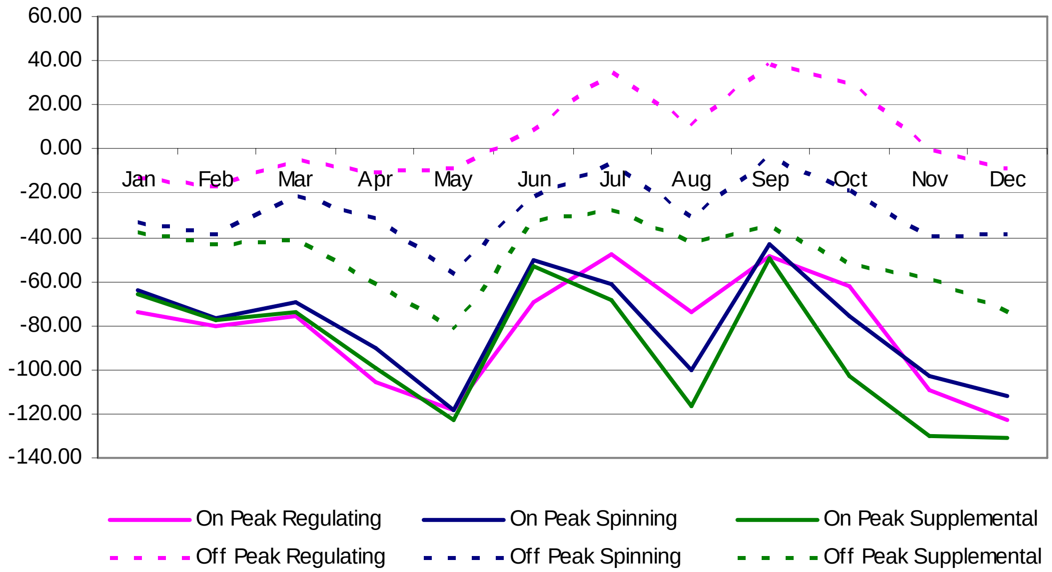
Figure xvi - Volumes Traded D-5 through D-1 on NGX



4.2 Trade Price on NGX

The trade indices are volume weighted average prices of the different trading days. In the second half of 2008, the trade indices were mostly driven by the (D-1) trading as the largest volumes were traded on (D-1). Figure xvii shows the trade indices of the OR products on NGX. The trade indices don't suggest that by moving volumes to D-1 resulted in the AESO being "cornered".

Figure xvii - Trade Indices for Active OR Products



Setting stable bid prices at levels that were expected to incent all the providers to compete impacted trade prices in two ways. First, since the trade price is the mid-point between bid and offer, with stable bids the traded price moves only with the change in the offers that clear the market. Secondly, since the bid prices are set at levels that all the providers were expected to compete (i.e. high enough to incent the high opportunity cost resources to compete), the bid prices to some degree contributed to higher trade prices. However, increased active competition put downward pressure on trade prices. The increased level of competition is evident in that four of the six active products had, on average, lower trade indices in the last 5 months of the year compared with the first 7 months.

4.3 Participation and Market Share

In 2008 new resources and new participants were added in the OR market and a total of 16 participants successfully sold at least one type of product. Figures xviii & xix depict the market share of the active and standby products traded on NGX. They show that some participants were more competitive in the active market while others were more competitive in the standby market. The competitiveness is to a large degree determined by the type of resource a participant owns and therefore the opportunity costs associated with providing the particular OR products.

Figure xviii - Market Share of the Active Products on NGX, 2008

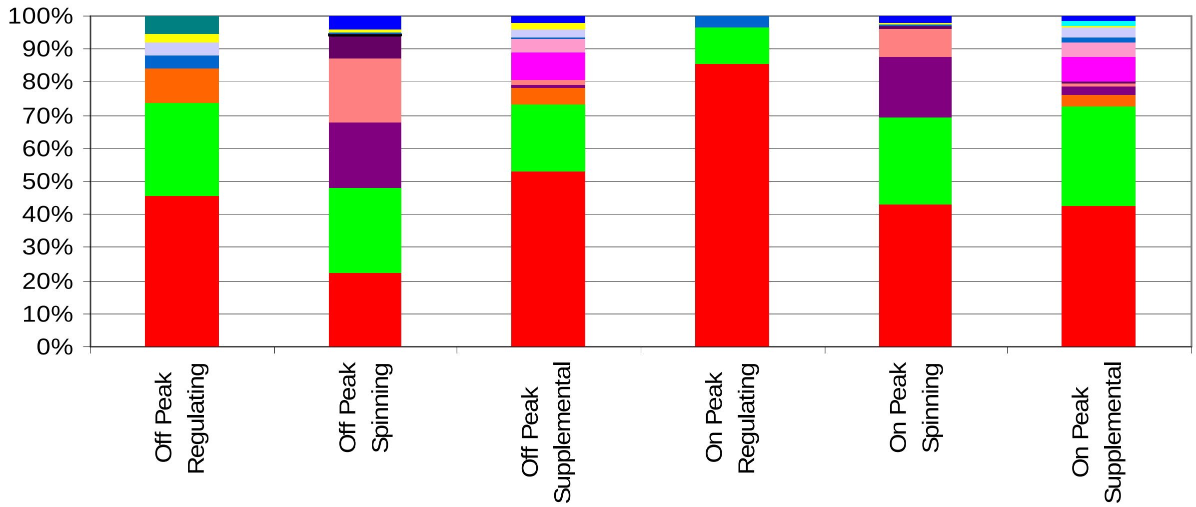
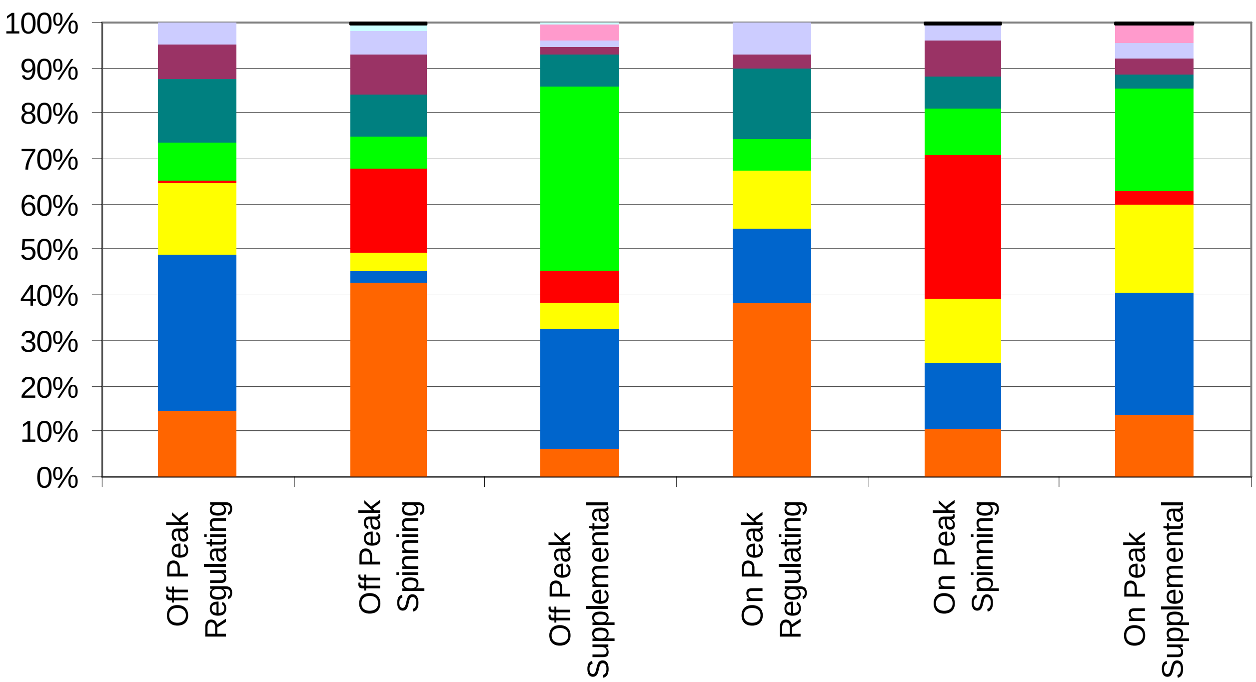


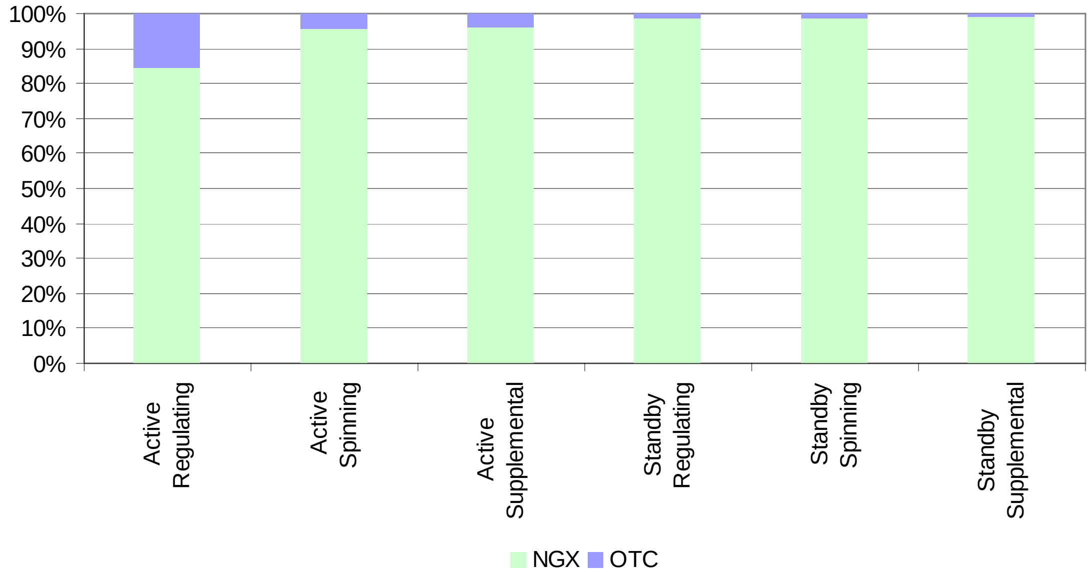
Figure xix - Market Share of the Standby Products on NGX, 2008



4.4 OTC Procurement

The majority of the OTC volumes were the "shaped volumes", meaning volumes varying by hour that don't fit the on-peak or off-peak definitions of NGX's standard contract. In 2008, except for the active regulating reserves, of which about 18% was procured on OTC, all other products were predominantly traded on NGX (Figure xx). The OTC procurement volumes have been stable since mid 2007 when AESO changed its procurement practices.

Figure xx - OR Procurement Share on NGX and OTC, 2008



4.5 Average Prices vs Cost on New Entry

The average cost per MW to load in 2008 of the three active products is shown below:

- Regulating Reserve $50.91
- Spinning Reserve $43.61
- Supplemental Reserve $38.03

The net revenue analysis described in Section 1.2 focused on revenues from the energy market. Naturally, revenues can be obtained from any relevant market and here we look briefly at participation in the OR market for the new entrants. As an example, an LM6000 unit can sell supplemental reserves with virtually no use of fuel. Assuming supplemental reserves were sold for the entire year and allowing for outages would yield an income of about $313,000/MW. Subtracting fixed O&M would yield a net revenue of about $256,000/MW, or 26% of capital cost. This is more than the estimated revenue from the energy market which was calculated as 20%.

Caution is required in interpreting this result as the individual OR markets are quite small and the price depressing effect of a new entrant would be more extreme than in the energy market.

The MSA intends to examine this relationship more closely in the future and will report any interesting findings in its quarterly reports.

5 OTHER MSA ACTIVITIES

5.1 Investigations Update

The MSA investigated three issues during 2008. These issues concerned trading in the Ancillary Services market, uneconomic importing and trading in the forward market prior to disclosure of outage information.

5.1.1 Trading in the Ancillary Services market

The MSA initiated a formal investigation into certain trading activity in the Ancillary Services market on May 14, 2007. The investigation was concluded on November 14, 2008.

The MSA investigation determined that the AESO and certain counterparties would periodically, through direct bilateral communications, negotiate the specifics of a trade for operating reserves required by the AESO and to be supplied by the counterparty. These trades would then be posted and executed on the Watt-Ex market, rather than completing the transaction as on Over-the-Counter (OTC) trade. The MSA is of the opinion that this conduct can properly be considered "pre-arranged trading" on the Watt-Ex market.

The MSA conducted a comprehensive investigation and identified a number of pre-arranged trades in the Standby Regulating, Spinning and Supplemental AS products as well as a few pre-arranged trades in the Active Term Regulating and Supplemental AS products. The MSA did not find any evidence of intent by the AESO or the counterparties to manipulate or distort market prices. In addition, prices for the pre-arranged transactions were generally consistent with market prices before and after the trades. The MSA found no financial harm to the market as a result of the conduct and, accordingly, concluded the investigation.

The MSA commends the AESO and counterparties who cooperated with the MSA's investigation and voluntarily provided access to employees, documents and trading records to assist in the investigation.

Trading in the Ancillary Services market also falls within the jurisdiction of the Alberta Watt Exchange Ltd (Watt-EX) and the Alberta Securities Commission (ASC). Pursuant to Section 45 of the AUCA, the MSA submitted information it obtained concerning its investigation to Watt-Ex as well as to the ASC for their review and consideration.

5.1.2 Uneconomic importing

The MSA initiated an investigation into certain imports of energy by ENMAX Energy Corporation and ENMAX Energy Marketing Inc. in October 2005. The MSA is concerned about the uneconomic importation of energy into Alberta and the potential undesirable impact this may have on Alberta energy prices. As part of the investigation, the MSA interviewed employees of ENMAX who were advised by ENMAX's legal counsel not to answer specific questions. The MSA applied to the Court of Queen's Bench on February 15, 2007 for an order compelling the ENMAX employees to answer questions. On January 24, 2008

Mr. Justice A.D. Macleod filed his decision in this matter and dealt with the questions that had been objected to by ENMAX (2008 ABQB 54). The court ruled that all of the objected to questions are appropriate and the MSA is allowed to re-interview the witnesses who will answer the questions previously objected to. Moreover, the MSA is entitled to ask further questions following up on the answers given to the objected questions.

Pursuant to the court's decision the MSA re-interviewed ENMAX employees and completed its information-gathering process. The MSA subsequently prepared draft Facts and Findings and submitted the document to ENMAX for review and comment. The MSA expects to complete the investigation in 2009.

5.1.3 Trading in the forward market prior to disclosure of outage information

The MSA commenced an investigation into specific forward market trading activity early in 2008 after receiving a referral from a market participant. The referring party was concerned that the trading activity occurred in advance of outage disclosure and may have been contrary to the Trading Practices Guideline (TPG). The MSA held a number of meetings with the parties involved in the trading activity and determined that it had occurred in a manner consistent with the TPG and, accordingly, closed the investigation.

5.1.4 MSA activities related to investigations

In the course of its investigations over the past several years a number of related matters have come to the attention of the MSA. Some of these matters include: the use of unrecorded instant messages for trade negotiations and confirmations, the extent and adequacy of internal training, clock-setting standards and the extent and effectiveness of internal governance and oversight. The MSA intends to give these areas further thought during 2009 and may engage market participants in related discussions in order to obtain their input on what might constitute appropriate practices in these areas.

5.2 ISO Rules Compliance Enforcement

The new Alberta Utilities Commission Act (AUCA) which came into force January 1, 2008, in conjunction with amendments to the Alberta Electric Utilities Act (EUA), clarified the roles and responsibilities of the AESO, the MSA and the AUC as to ISO rules compliance and enforcement. A key driver of these legislative developments, as communicated by the Alberta Department of Energy (DOE), was to clearly partition the roles of rule maker, rule enforcer, and rule adjudicator within the Alberta electricity market.

Under the new legislation, the AESO retained a mandate to monitor the compliance of market participants with ISO rules. The enforcement role now solely rests with the MSA, and the AUC acts as final adjudicator.

Suspected breaches of ISO rules are identified through AESO compliance monitoring activities, self-disclosures by participants, or identified through the regular market monitoring activities of the MSA itself.

The Alberta Utilities Commission Act Transition Regulation governed the manner of transitioning AESO responsibility for rules compliance issues to the MSA. Remaining files handled by the prevailing AESO compliance process continued to be dealt with through the existing ISO rule 12 process.

A significant development during 2008 related to changes to AUC Rule 019. The amended rule categorizes specific ISO rules that can be enforced and adjudicated within the penalty table(s), and specifies the financial penalty based on the rule itself and non-compliance history with the given rule. ISO rule 6.6 (dispatch compliance) is treated as a separate category and penalty table, with pre-determined financial penalties based on the magnitude and duration of a dispatch variance.

The previous version of the AUC Rule 019 contemplated penalties ranging from a warning letter to a financial sanction. However, warning and non-compliance letters are not contemplated by the new AUC Rule 019. Further, financial penalties were modified to pre-set amounts (as opposed to a range of possible penalty amount).

Figure xxi shows a breakdown of the ISO rules applicable to the suspected contraventions dealt with by the MSA in 2008. Figure xxi also details the penalties imposed by the MSA by ISO rule as of year-end. As shown by this data, ISO rules 6.6 (dispatch compliance) and 3.5.3 (energy offers and restatements) comprised a substantial proportion of compliance events brought to the attention of the MSA during the year. This is not surprising given that compliance with dispatch instructions and the need to properly declare unit availability are important for the integrity of the price signal and for the System Controller's ability to balance load and generation in real time.

In Figure xxi, Forbearance denotes events in which a rule breach was suspected but where there were sufficient operational or mitigating circumstances such that the MSA chose not to pursue the event further. In the case of rule 6.6, certain events were not pursued with sanction due to physical plant issues rendering the unit unable to respond to dispatch. In addition, broader based forbearance was extended with respect to new rules coming into force with the implementation of "Quick Hits". In particular, for rule 3.5.3, letters to address apparent rule contraventions were directed to a number of participants in an effort to raise awareness of the new rules in the weeks following their implementation and to convey expectations of the AESO and the MSA going forward. Certain non-pursued rule 6.6 contraventions also related to quick hits implementation insofar as initial confusion regarding concurrent DDS and energy obligations. In a more steady state rules environment, such levels of forbearance would not be expected.

The absence of certain ISO rules from the AUC Rule 019 penalty table does not preclude MSA enforcement of a rule contravention. In accordance with Section 51 of the AUCA, the MSA may bring any alleged breach of the ISO rules to the AUC for consideration.

Compliance monitoring activities during 2008 resulted in the issuance of 7 notices of specified penalty totaling $30,000 in financial sanctions ranging from $2,000 to

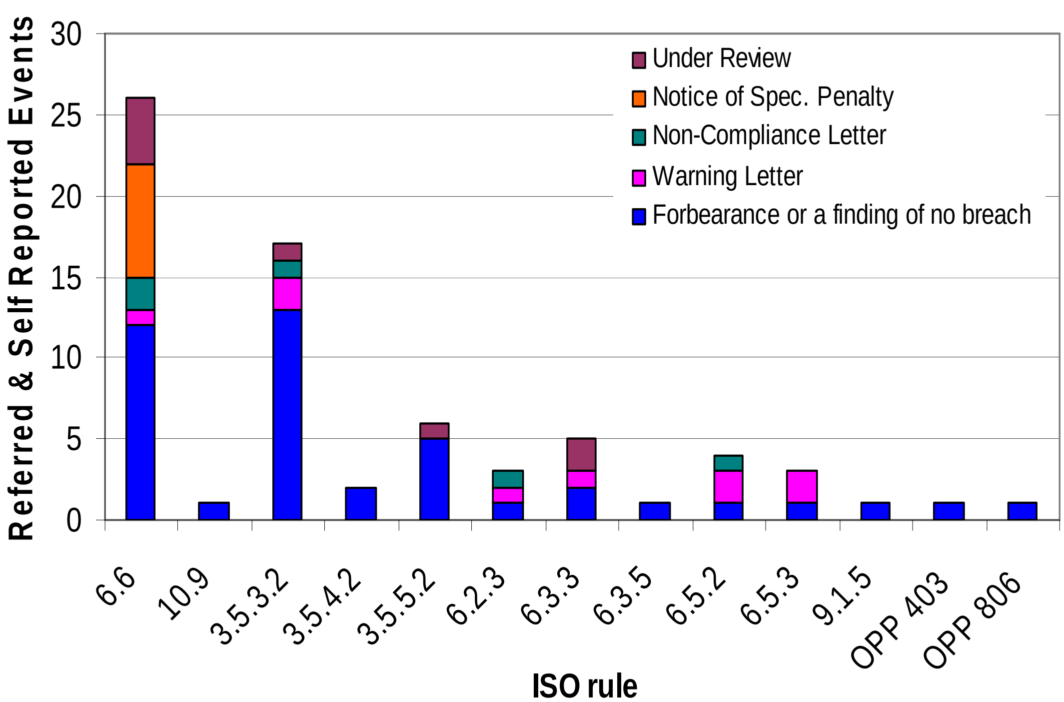
$8,000 each. In each case where a financial sanction was imposed, the participant in question had contravened the same rule not less than three times within the trailing 12 month period. In addition, the MSA issued 9 warning letters and 5 non-compliance letters. At year-end, 8 files remained under review to be concluded in 2009.

Two of the notices of specified penalty issued in 2008 were disputed and went to litigated hearings before the AUC (AUC proceedings ID 71 and ID 75). In both cases the AUC confirmed the financial penalty assessed by the MSA.

Both of those proceedings involved non-compliance events with respect to ISO rule 6.6. Although each had a unique fact pattern, both cases were argued on a 'strict liability' basis whereby a defense of due diligence is available. In both decisions (AUC 2008-114 and AUC 2008-126) the AUC conveyed a high standard to the claim that the participant took all reasonable steps to prevent the contravention.

In another instance, a payment of a specified penalty was received late leading to the MSA making an application with the AUC (proceeding ID 115). In an order dated January 26, 2009 (Order M2009-001) the AUC ordered the payment of accrued interest resulting from the late payment in accordance with subsection 4(2) of the Alberta Judgment Interest Act. Insofar as the awarding of costs, the MSA had waived its claim to costs in that specific instance but affirmed its intention to pursue costs where appropriate in future cases.

Figure xxi - Disposition of Reported Events, 2008



5.3 MSA Guidelines and Stakeholder Consultations

During the year the MSA conducted three stakeholder consultations, resulting in an Intertie Conduct Guideline, a revision to our Investigation Procedures and an evaluation of the consultation process.

5.3.1 Intertie Conduct Guideline

The MSA initiated a stakeholder consultation process concerning the development of a new guideline dealing with intertie conduct on May 7, 2008. Following two rounds of input from stakeholders the MSA published the final MSA Guideline: Intertie Conduct on July 14, 2008.

The guideline provides guidance to market participants regarding types of transactions to be avoided, what a participant should reasonably expect when considering an import or export, the MSA's expectations concerning the economics of the import or export relative to the next best alternative and the retention of records necessary to support and explain the intertie transaction.

5.3.2 Revision to Investigation procedures

The MSA published revised Investigation Procedures on April 4, 2008 after conducting a stakeholder consultation process. The purpose of revising the Investigation Procedures was to ensure that they are described in sufficient detail so that persons referring matters to the MSA, parties under investigation, other market participants and the general public will generally know what to expect with respect to communications and points of contact once a matter has come to the attention of the MSA.

On July 8, 2008, the MSA further amended the investigation procedures in relation to the new AUC Rule 019 which requires a market participant to self-report an Independent System Operator (ISO) rule contravention to the MSA, and to provide (at a minimum) a set of required information in that regard. The amended Investigation Procedures went into effect on July 9, 2008.

5.3.3 Evaluation of Stakeholder Consultation Process

The MSA, with input from stakeholders, developed its Stakeholder Consultation Process from May to July 2006. At that time the MSA committed to evaluate the process once it had some experience in the practical application of the process. On July 28, 2006 the MSA published a summary of its views on the efficacy of the process and invited comment from stakeholders. Based on a review of the comments received the MSA concluded that the process was meeting its objectives.

APPENDIX A – WHOLESALE ENERGY MARKET METRICS

Table 1 – Pool Price Statistics

	Average Pool Price	Average On-Peak Pool Price[1]	Average Off-Peak Pool Price[2]	Std Dev[3]	Coeff. Variation[4]
Jan-08	80.30	98.56	55.02	96.23	120%
Feb-08	64.89	74.99	51.24	38.31	59%
Mar-08	84.89	99.51	66.30	90.37	106%
Apr-08	135.95	173.08	85.15	160.99	118%
May-08	103.73	137.54	56.90	112.12	108%
Jun-08	83.00	125.96	29.31	154.18	186%
Jul-08	64.51	81.01	41.67	64.80	100%
Aug-08	82.72	114.86	41.95	120.21	145%
Sep-08	93.86	135.29	37.15	172.28	184%
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%
2008	89.95	117.05	53.74	129.54	144%
2007	66.95	86.30	41.13	103.73	155%

1 - On-peak hours include HE08 through HE23, Monday through Saturday (prevailing Mountain Time)

2 - Off-peak hours include HE01 through HE07 and HE24 (of the current day) Monday through Saturday, and HE01 through HE24 Sundays (prevailing Mountain Time)

3 - Standard Deviation of hourly pool prices for the period

4 - Coefficient of Variation for the period (standard deviation/mean)

Figure 1 – Pool Price Duration Curves

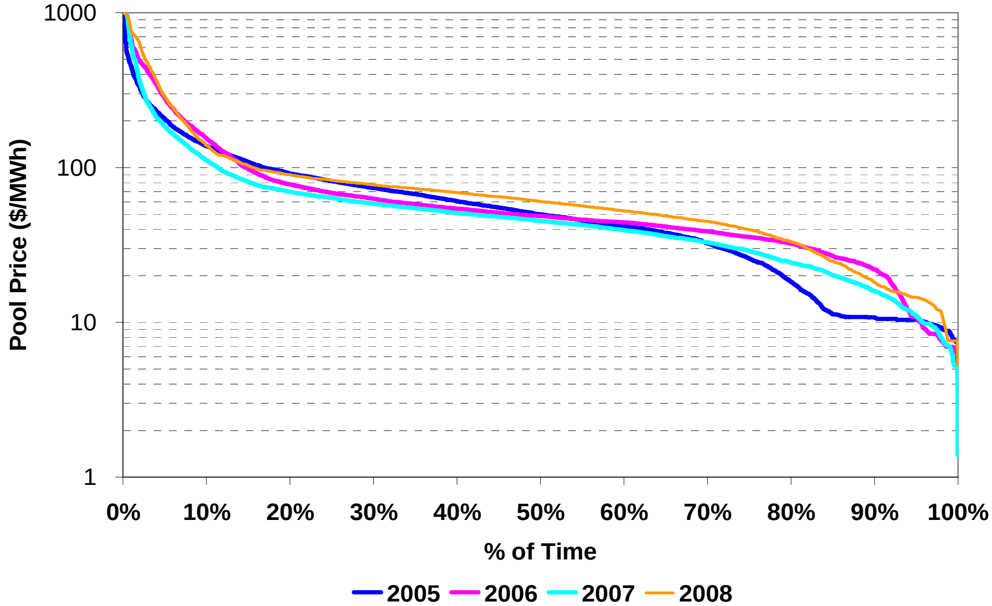


Figure 2 - Pool Price with Pool Price Volatility

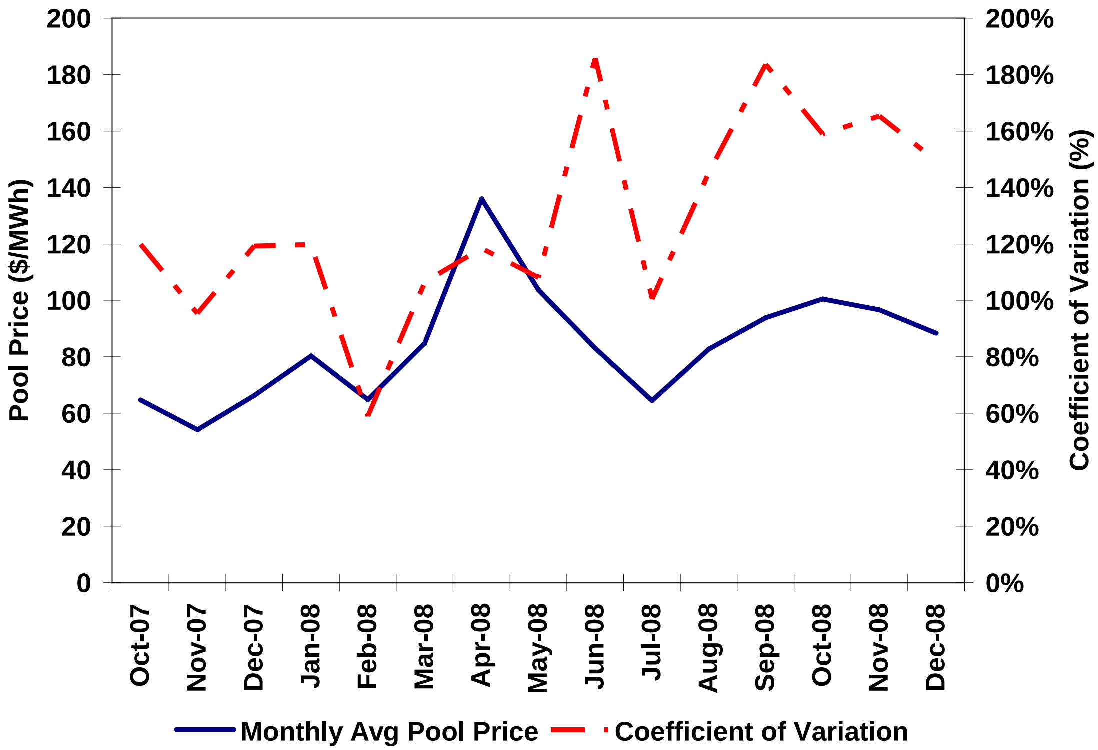


Figure 3 - Pool Price with AECO Gas Price

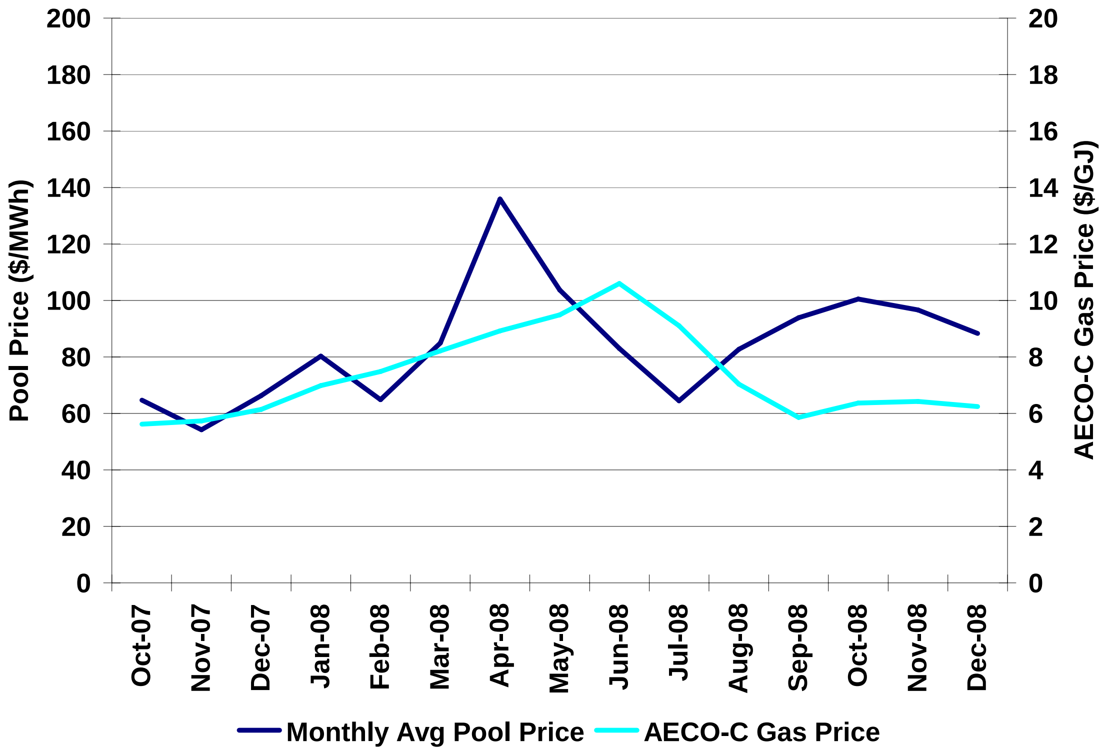


Figure 4 - Price Setters by Pool Participant (All Hours)

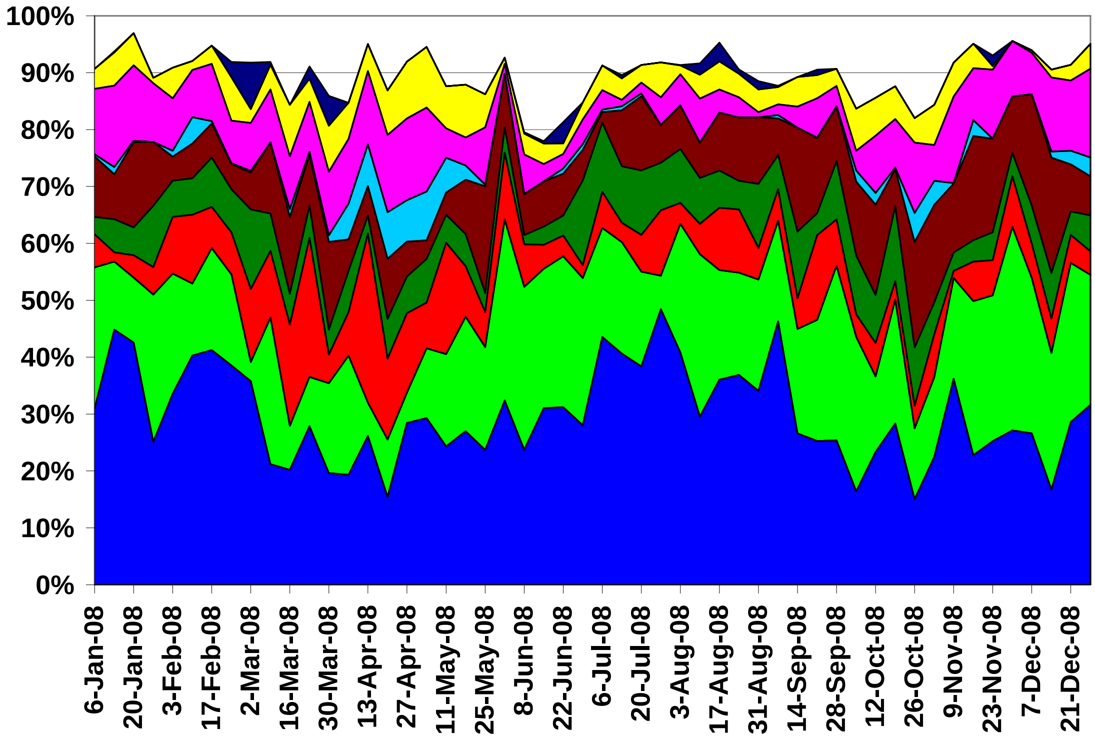


Figure 5 - Price Setters by Fuel Type (All Hours)

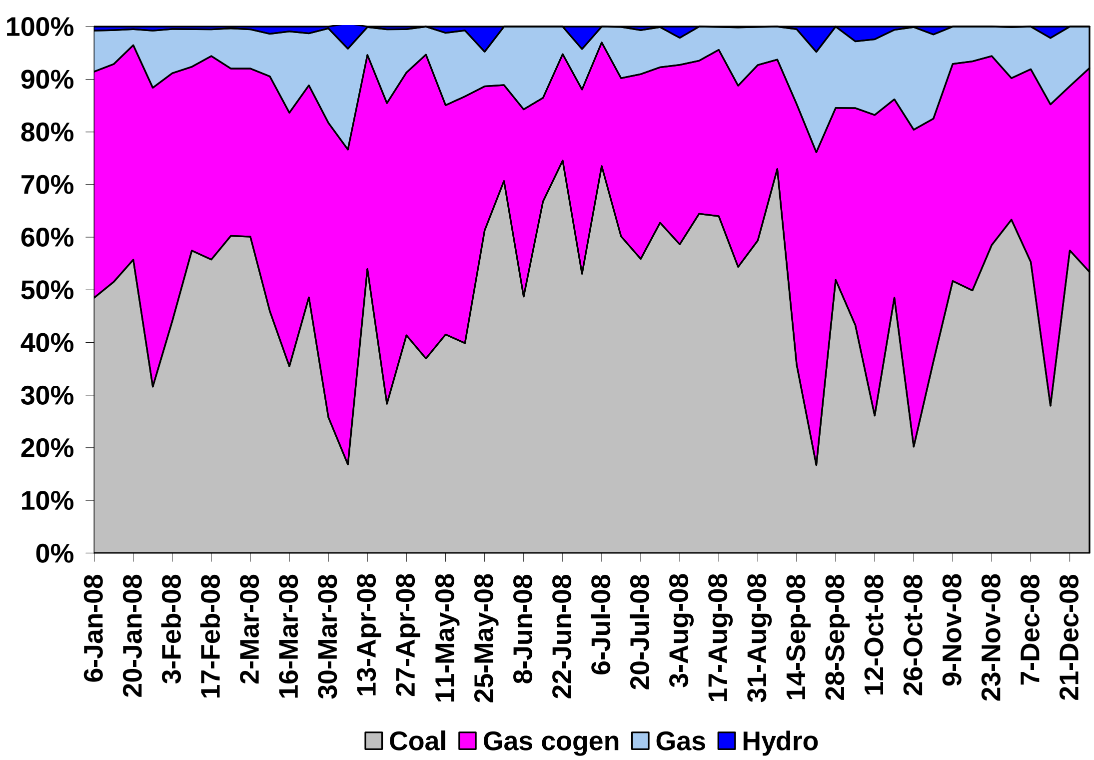


Figure 6 - Heat Rate Duration Curves (All Hours)

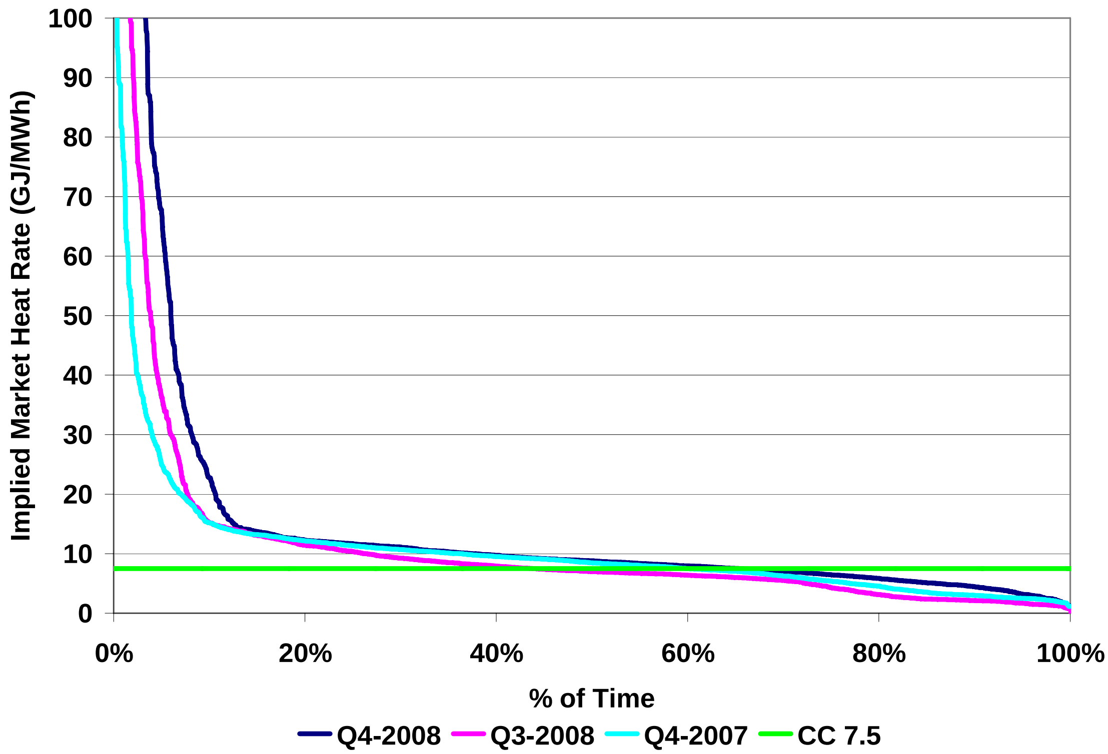


Table 2 - Implied Market Heat Rates (2008)

Month	On-Peak	Off-Peak	All Hours
January	14.09	7.76	11.43
February	10.04	6.91	8.70
March	12.06	7.96	10.25
April	19.79	9.56	15.47
May	14.50	6.02	10.94
June	11.83	2.80	7.82
July	9.12	4.78	7.30
August	16.09	5.99	11.64
September	23.21	6.43	16.13
October	21.69	7.74	15.84
November	21.87	9.58	16.40
December	15.73	11.60	14.00
Average	15.83	7.25	12.16

1 - On-peak hours include HE08 through HE23, Monday through Saturday (prevailing Mountain Time)

2 - Off-peak hours include HE01 through HE07 and HE24 (of the current day) Monday through Saturday, and HE01 through HE24 Sundays (prevailing Mountain Time)

Figure 7 - PPA Outages by Quarter

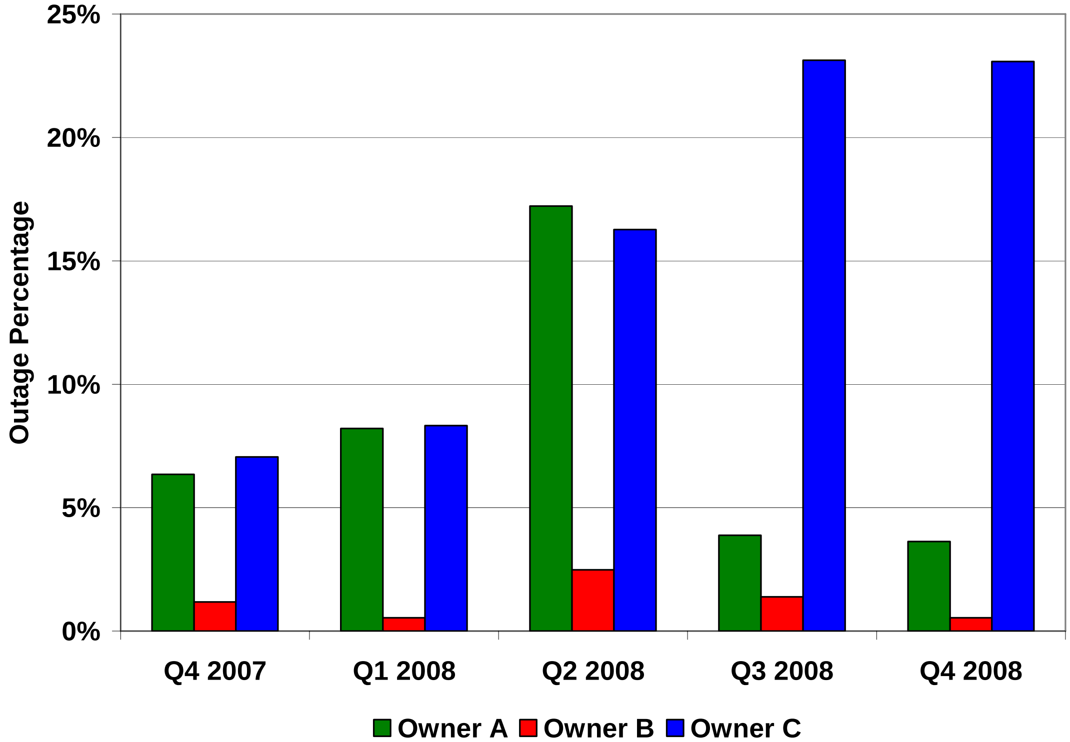


Table 3 - Percentage of Unplanned Outages for PPA Units

	Q4 2008	Q3/08	Q2/08	Q1/08	2008	2007	2006	2005	2004
Owner-A	**3.63%**	3.78%	3.6%	7.9%	**4.9%**	6.0%	5.2%	5.0%	6.1%
Owner-B	**0.37%**	1.39%	1.9%	1.9%	**1.0%**	1.8%	1.8%	5.4%	1.5%
Owner-C	**22.10%**	14.10%	11.4%	7.9%	**13.9%**	7.1%	5.3%	6.5%	6.3%
PPA weighted average	**13.48%**	9.20%	7.7%	6.9%	**9.3%**	6.0%	4.8%	5.9%	5.5%

Note:
1) PPA units include: Genesee 1 & 2, Battle River 3, 4, 5, Sheerness 1 & 2, Sundance 1 - 6, Keephills 1 & 2
2) Outages rates are based on maximum continous rating (MCR), not Maximum Capability.

Table 4 - MW Weighted Portfolio Target Availability (%) vs Actual Availability (%) -Coal Fired PPA Units

	Target Availability 2006	Actual Availability 2006	Target Availability 2007	Actual Availability 2007	Target Availability 2008	Actual Availability 2008	Actual Availability Q4 2008
Owner-A	87%	93%	87%	90%	87%	92%	96%
Owner-B	89%	98%	89%	98%	89%	99%	99%
Owner-C	87%	89%	86%	89%	86%	82%	77%
PPA weighted Average	87%	91%	87%	91%	87%	88%	86%

APPENDIX B – TIE LINE METRICS

Table 5 - 2008 Intertie Statistics

	British Columbia			Saskatchewan			Overall		
	Imports (MWh)	Exports (MWh)	Net Imports (MWh)	Imports (MWh)	Exports (MWh)	Net Imports (MWh)	Imports (MWh)	Exports (MWh)	Net Imports (MWh)
January	111,409	72,152	39,257	59,867	3,303	56,564	171,276	75,455	95,821
February	74,682	50,354	24,328	42,778	6,720	36,058	117,460	57,074	60,386
March	82,594	62,893	19,701	33,022	12,415	20,607	115,616	75,308	40,308
Q1-2008	268,685	185,399	83,286	135,667	22,438	113,229	404,352	207,837	196,515
April	122,878	35,795	87,083	91,796	0	91,796	214,674	35,795	178,879
May	122,059	23,818	98,241	55,938	600	55,338	177,997	24,418	153,579
June	242,436	0	242,436	58,462	1,982	56,480	300,898	1,982	298,916
Q2-2008	487,373	59,613	427,760	206,196	2,582	203,614	693,569	62,195	631,374
Jully	136,177	48,308	87,869	67,994	1,563	66,431	204,171	49,871	154,300
August	67,196	57,126	10,070	78,877	0	78,877	146,073	57,126	88,947
September	68,809	35,994	32,815	23,425	6,776	16,649	92,234	42,770	49,464
Q3-2008	272,182	141,428	130,754	170,296	8,339	161,957	442,478	149,767	292,711
October	198,233	26,397	171,836	53,121	607	52,514	251,354	27,004	224,350
November	141,003	43,208	97,795	62,959	558	62,401	203,962	43,766	160,196
December	186,031	61,803	124,228	44,739	5,361	39,378	230,770	67,164	163,606
Q4-2008	525,267	131,408	393,859	160,819	6,526	154,293	686,086	137,934	548,152
2008 Total	1,553,507	517,848	1,035,659	672,978	39,885	633,093	2,226,485	557,733	1,668,752

Figure 8 - 2008 Market Shares of Importers and Exporters

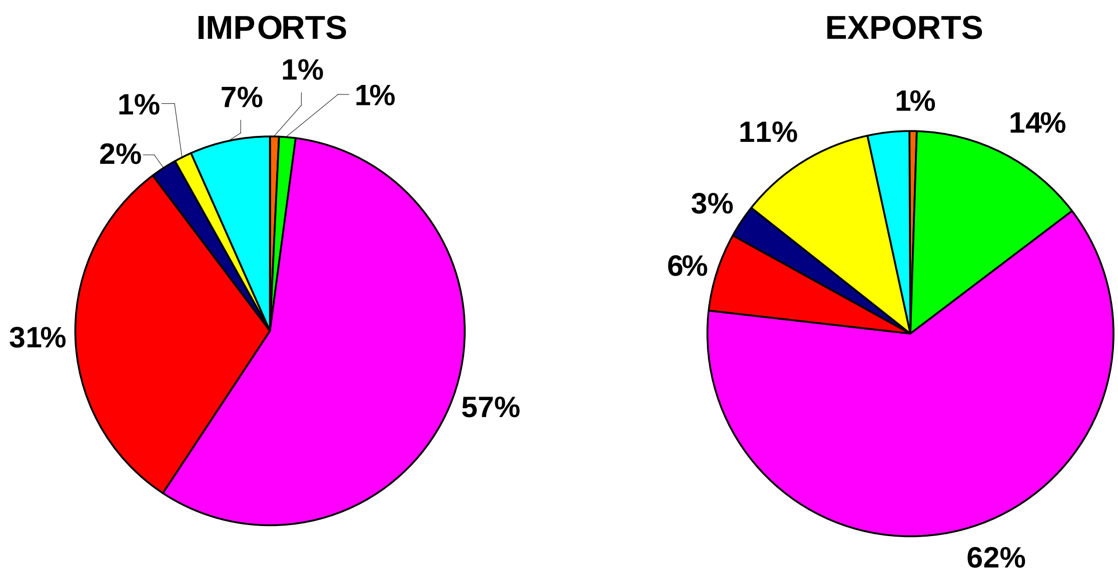


Figure 9 - 2008 Intertie Utilization

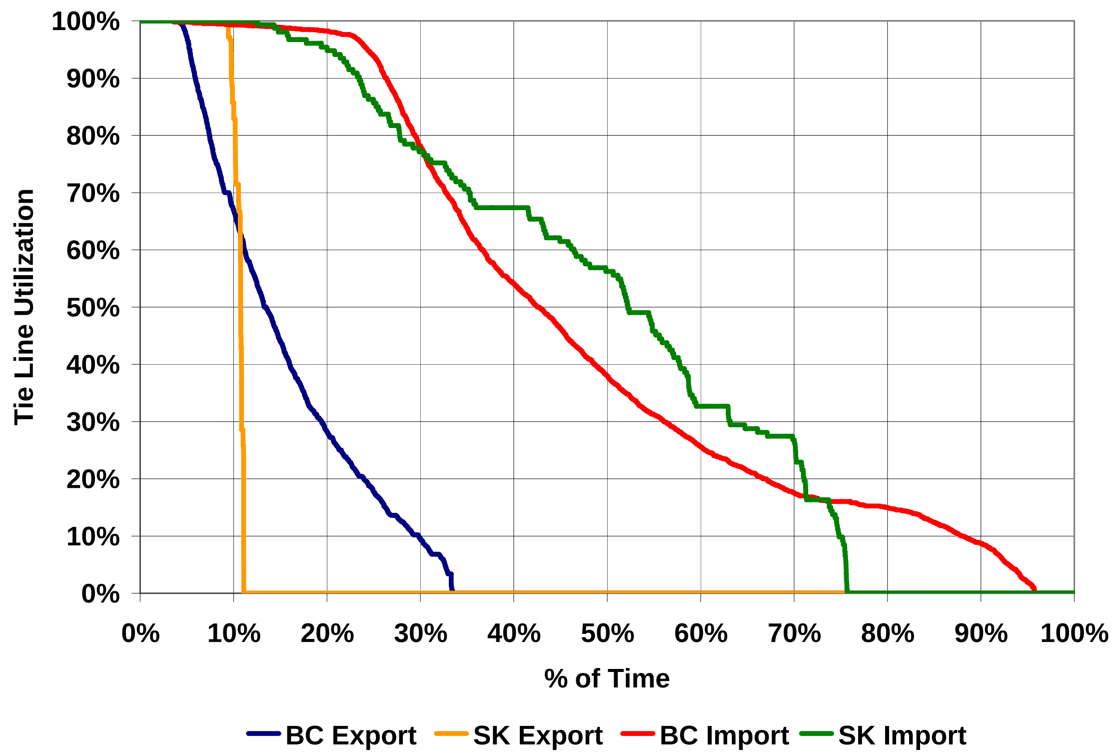


Figure 10 - Imports with Trade Weighted Prices

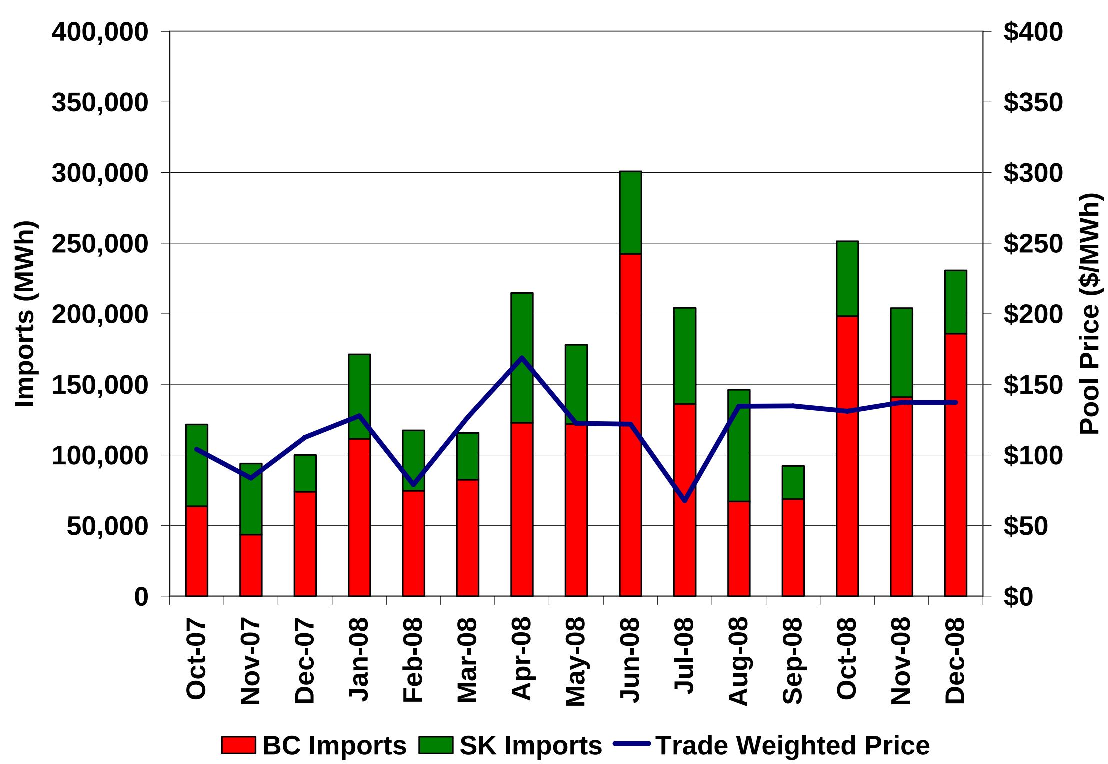


Figure 11 - Exports With Trade Weighted Prices

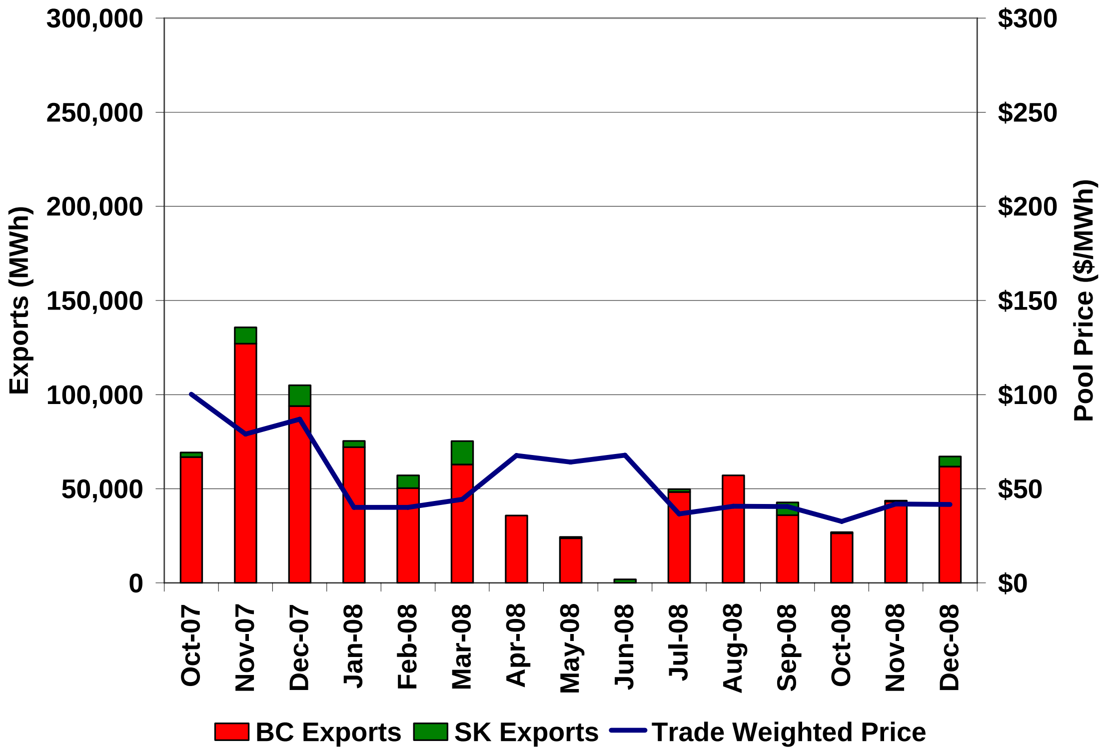


Figure 12 - On-Peak Prices in Other Markets

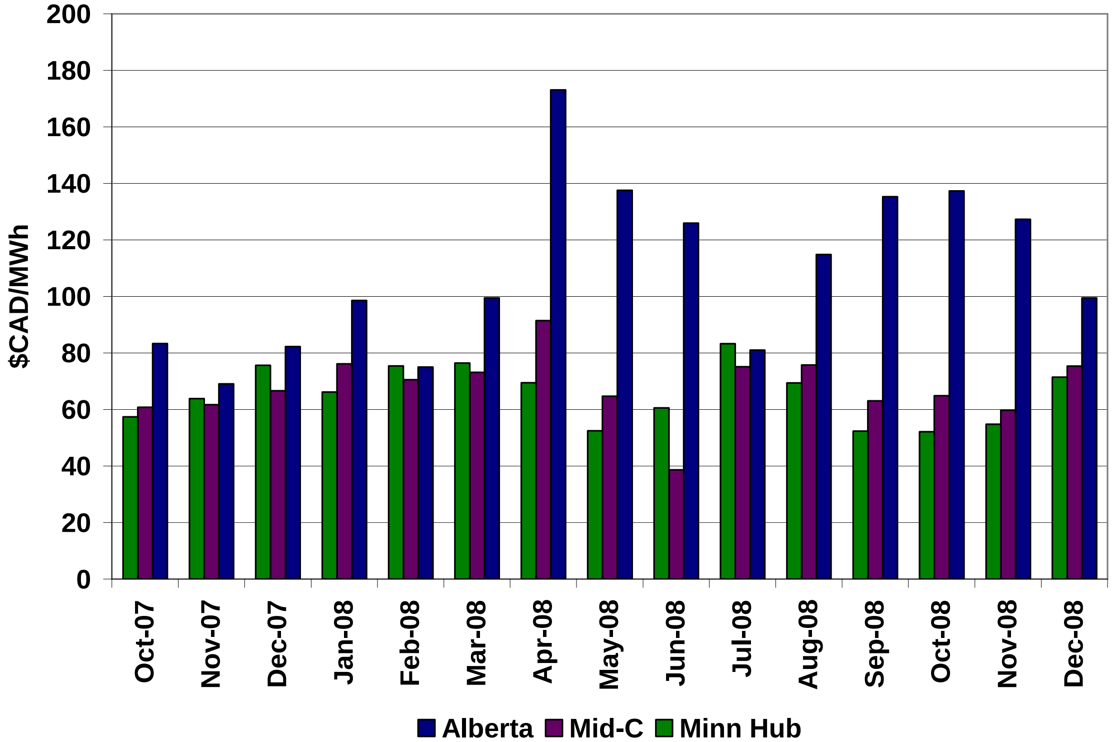
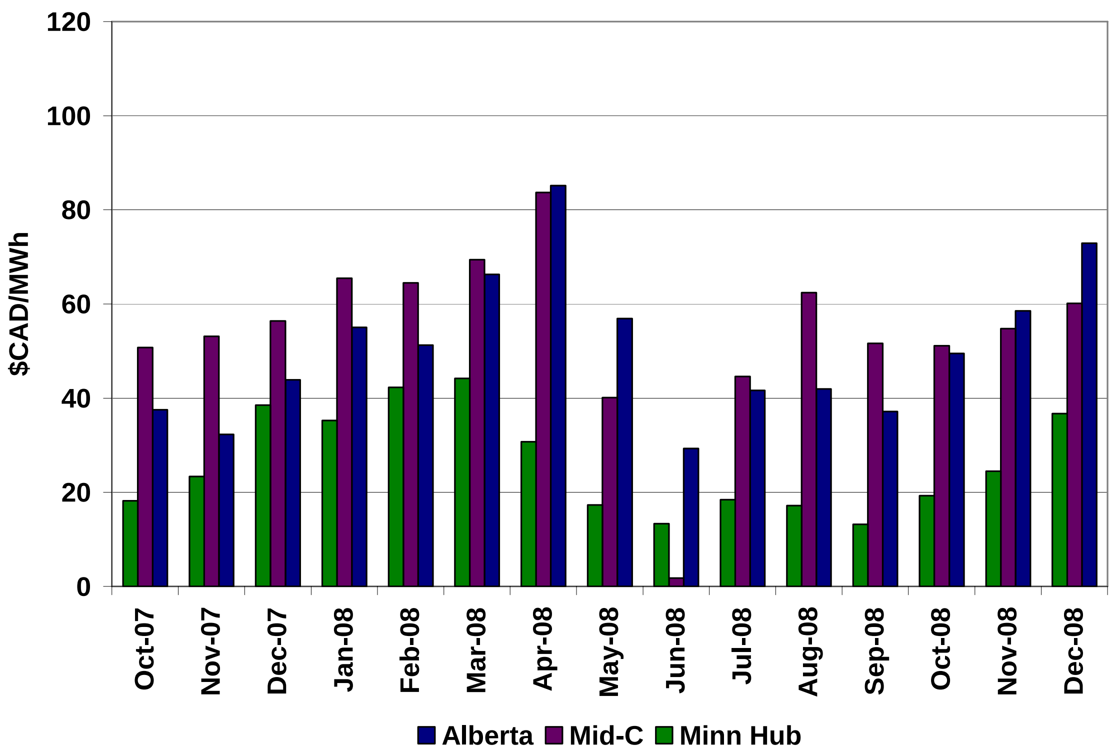


Figure 13 - Off-Peak Prices in Other Markets



APPENDIX C – ANCILLARY SERVICES 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 reserves in order to assist in the recovery of any unexpected loss of generation or an interconnection. Reserves are competitively procured by the AESO through the Alberta Watt-Exchange (Watt-ex) and over the counter (OTC). Standard ancillary services products (contracts) include active and standby products for each of Regulating, Spinning, and Supplemental reserves. The majority of active reserve products are indexed and settled against Pool price prevailing during the contract period. Standby 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 14 - Active Settlement Prices - All Markets (Watt-Ex and OTC)

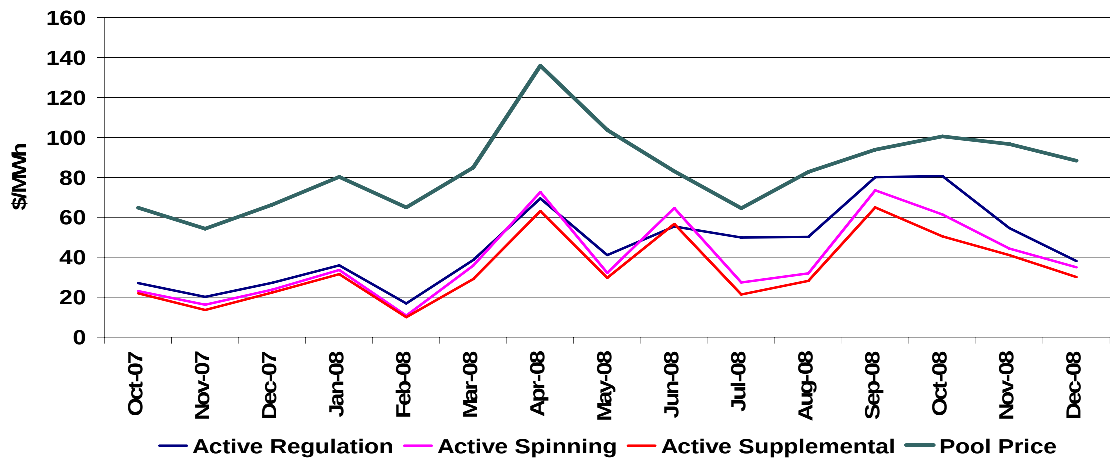


Figure 15 - Standby Premiums - All Markets (Watt-Ex and OTC)

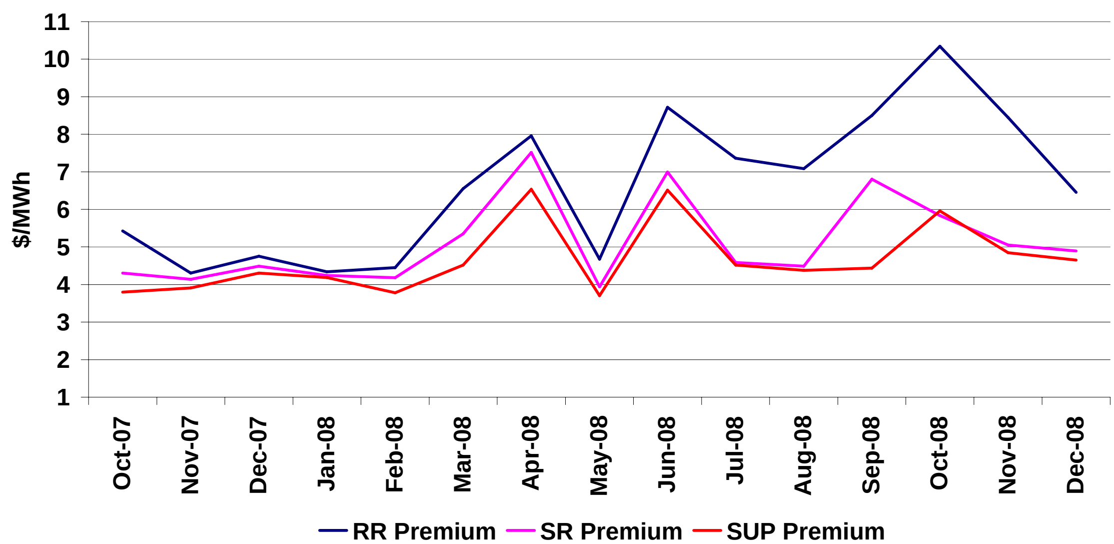


Figure 16 - Activation Prices - All Markets (Watt-Ex and OTC)

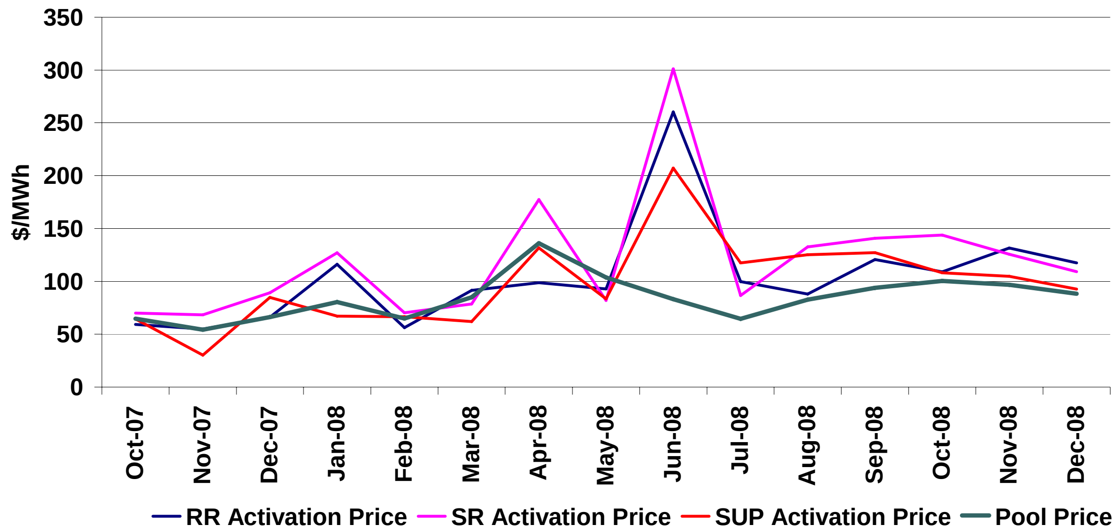


Figure 17 - Standby Activation Rates

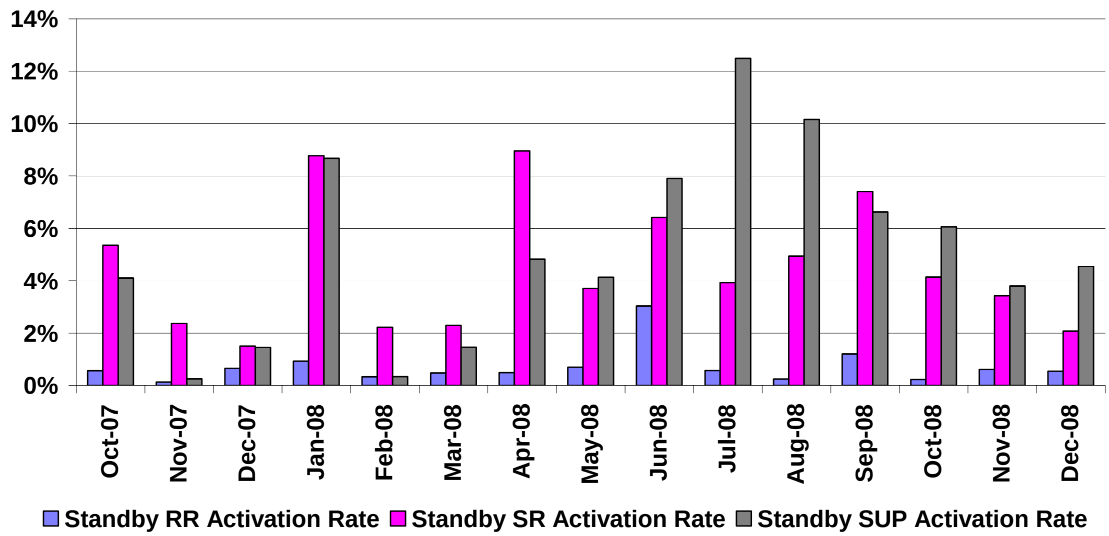


Figure 18 - OTC Procurement as a % of Total Procurement

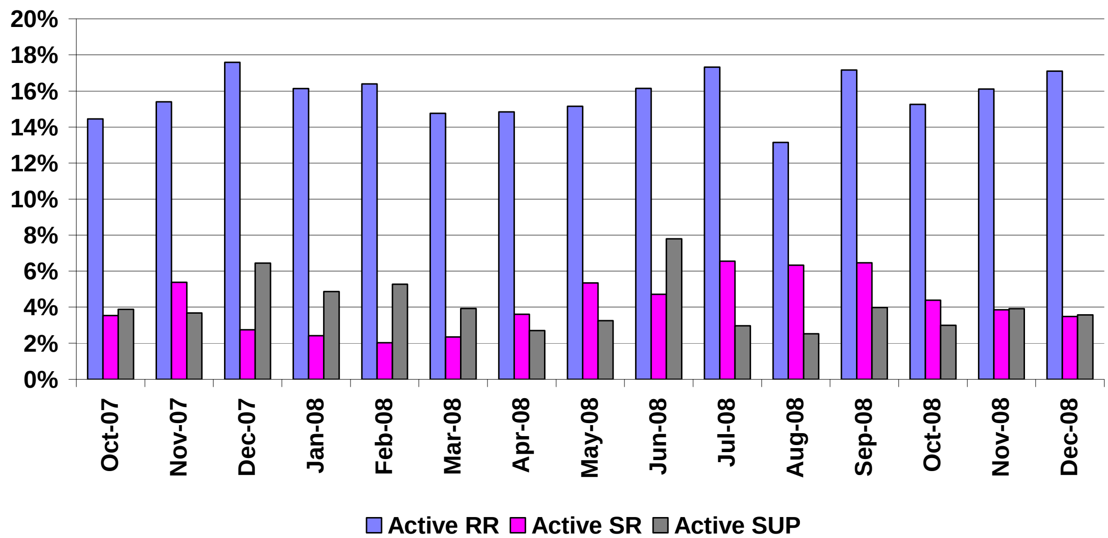


Figure 19 - Active Regulating Reserve Settlement by Market

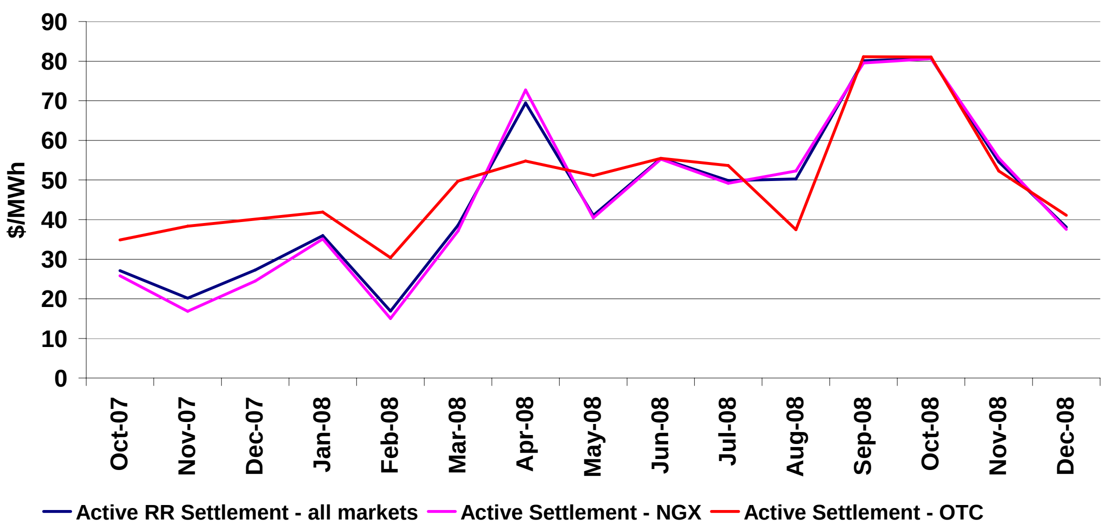


Figure 20 - Active Spinning Reserve Settlement Price by Market

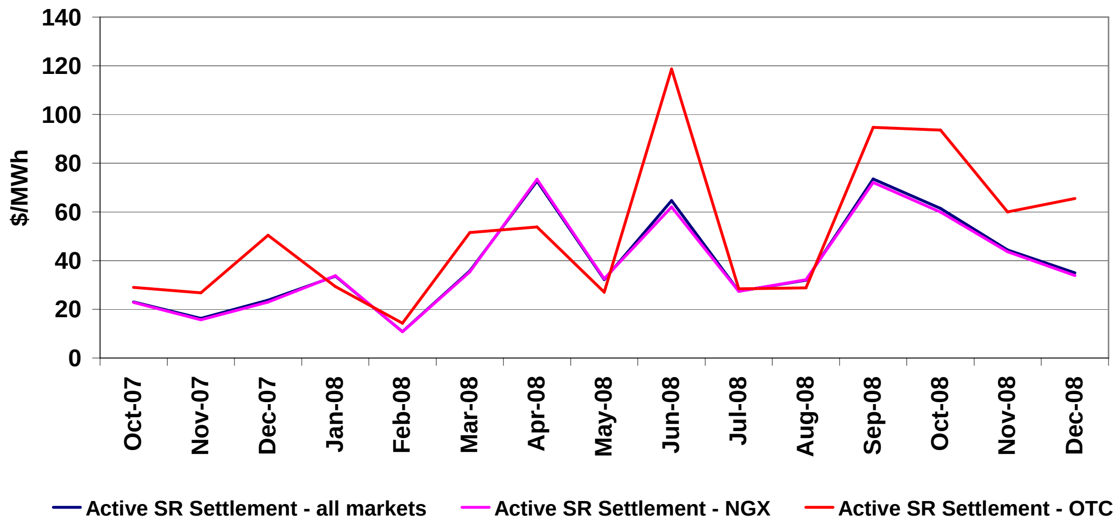


Figure 21 - Active Supplement Reserve Settlement Price by Market

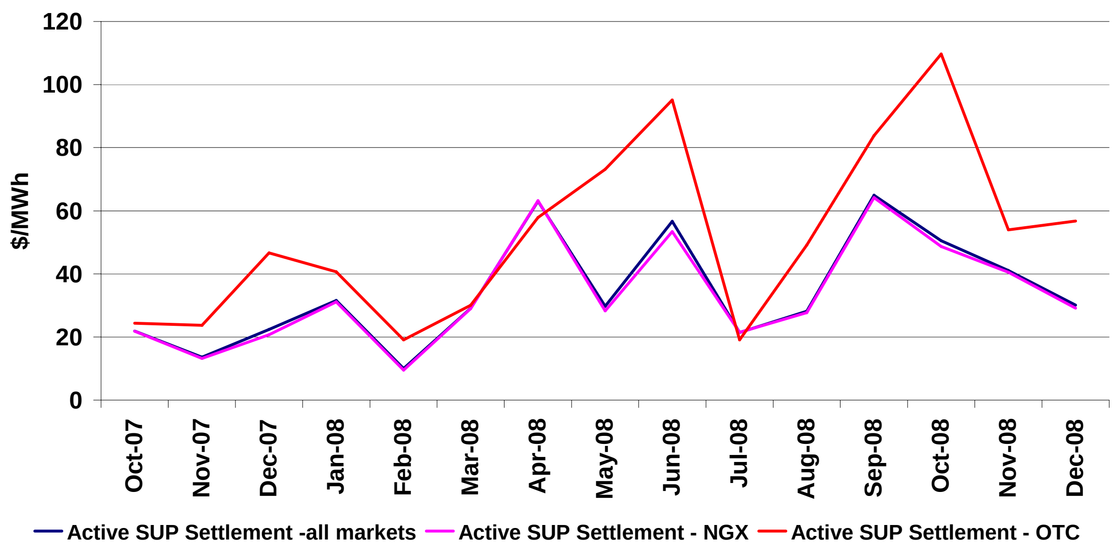


Figure 22 - Active Regulating Reserve Market Share by Fuel Type

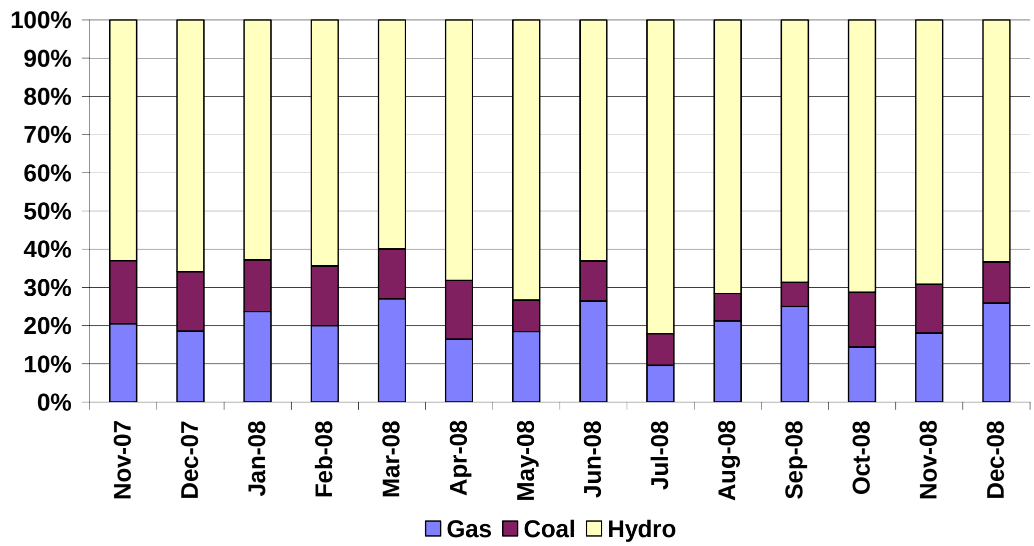


Figure 23 - Active Spinning Reserve Market Share by Fuel Type

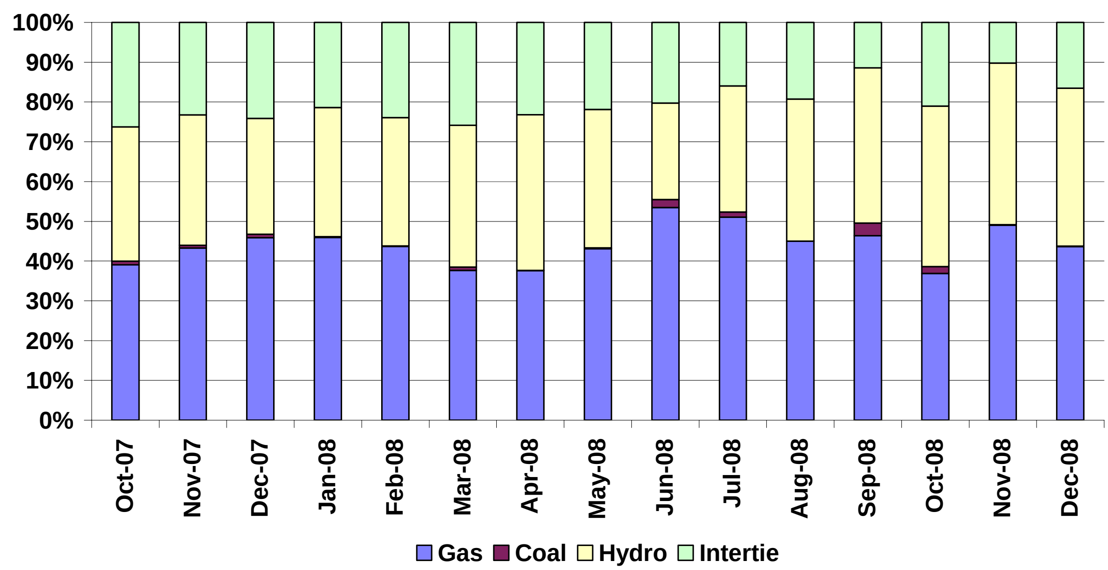
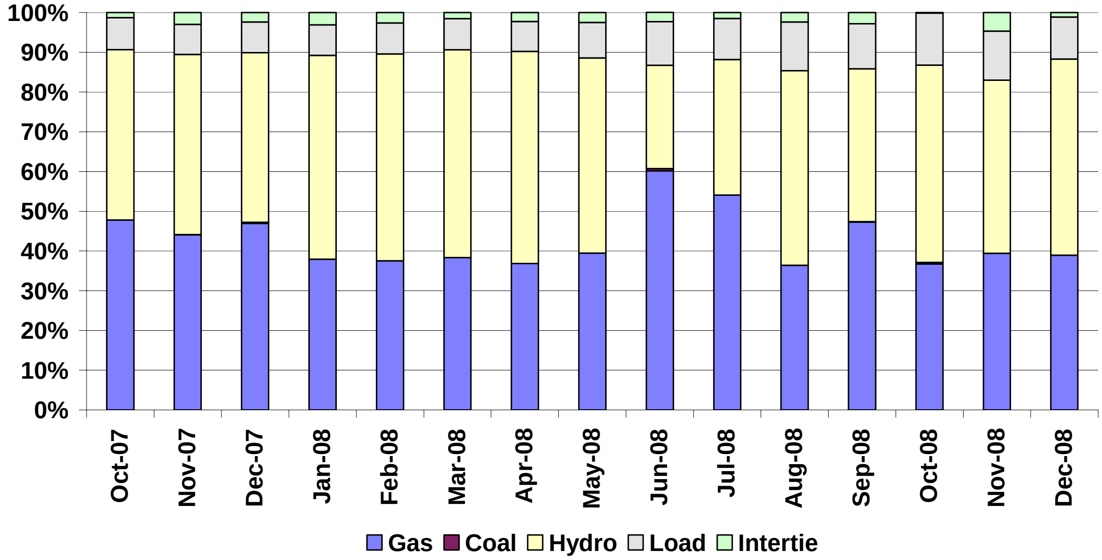


Figure 24 - Active Supplemental Reserve by Fuel Type



APPENDIX D – DDS METRICS

Table 6: DDS Costs and Revenues

Month	Total Payment ($M)	Total Dispatched (MWh)	Total Energy Production (MWh)	Estimated DDS Charge ($/MWh)	Estimated Revenue to DDS Providers ($/MWh)
	[A]	[B]	[C]	[A]/[C]	[A]/[B]
January	$2.09	61,793	5,341,376	$0.39	$33.79
February	$1.78	59,519	4,888,256	$0.36	$29.97
March	$2.30	63,105	5,008,405	$0.46	$36.50
April	$0.51	10,141	4,751,509	$0.11	$50.23
May	$1.72	33,203	4,652,007	$0.37	$51.74
June	$2.34	66,039	4,533,312	$0.52	$35.37
July	$2.81	66,592	4,914,923	$0.57	$42.17
August	$2.00	62,673	4,921,070	$0.41	$31.89
September	$1.56	54,056	4,600,770	$0.34	$28.93
October	$1.54	46,347	4,877,378	$0.32	$33.24
November	$4.15	95,473	4,842,591	$0.86	$43.43
December	$4.74	111,837	5,268,911	$0.90	$42.35
Total	$27.53	730,777	58,600,508	$0.47	$37.68

Figure 25: Average Daily TMR, Available, Eligible & Dispatched DDS Volumes (MW)

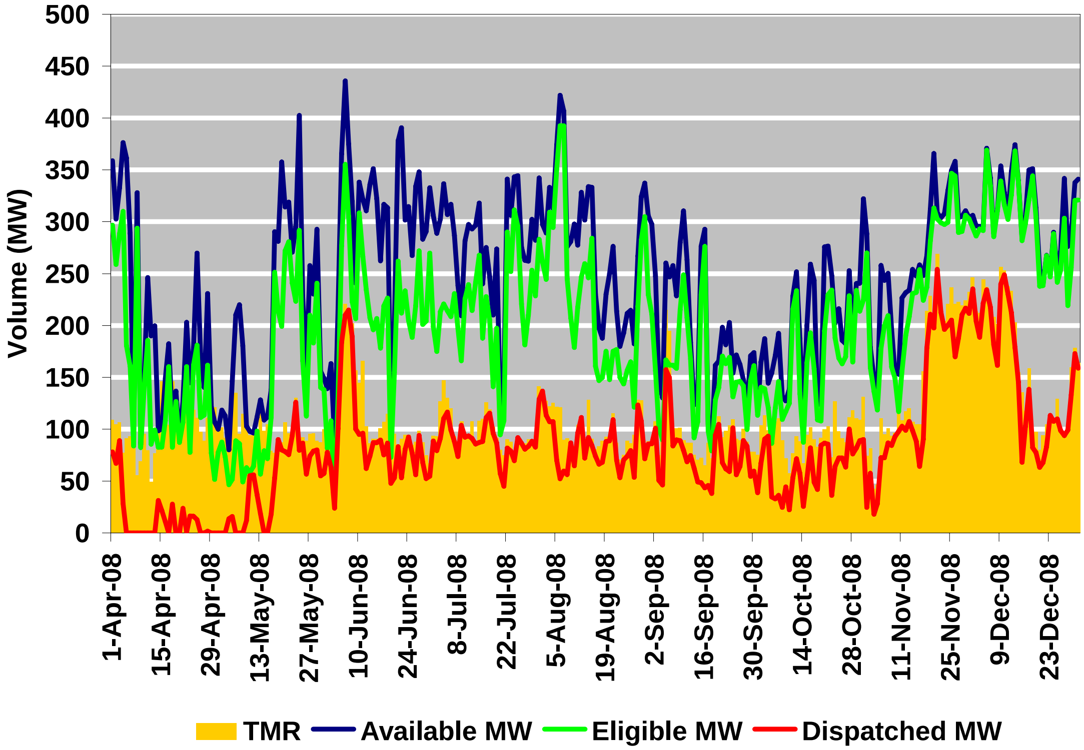


Figure 26: Average Daily DDS Dispatched and Constrained Down Volume (MW)

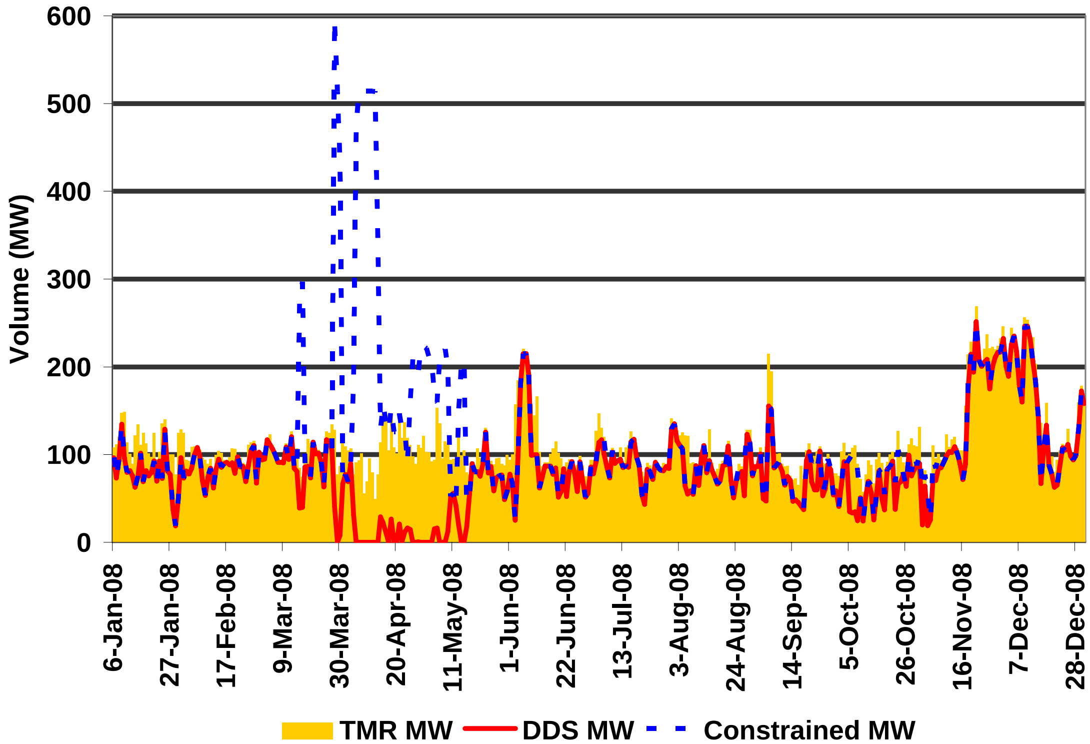


Figure 27: Average Weekly DDS Market Share by Submitting Participant

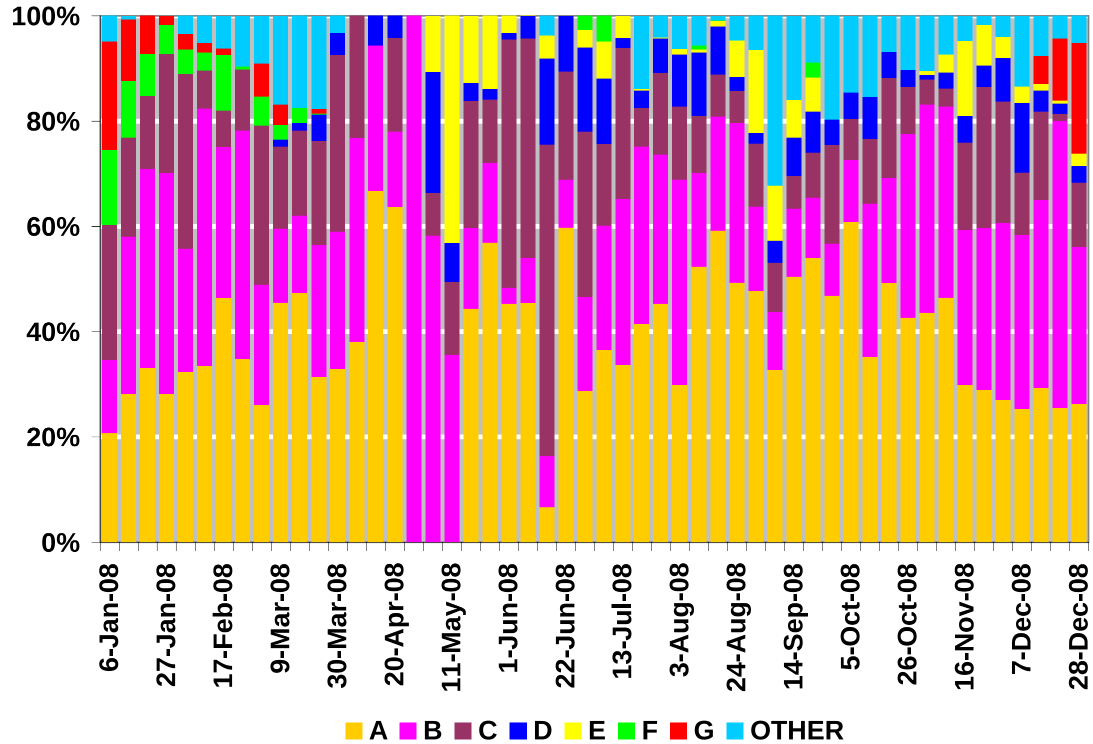
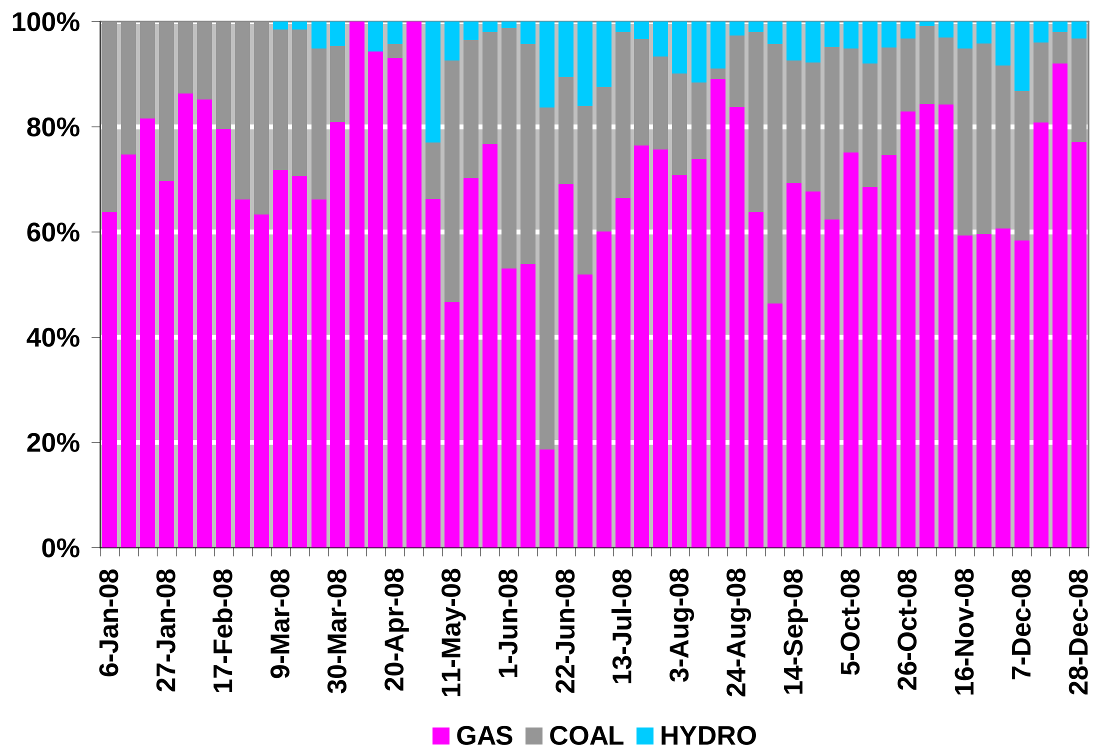


Figure 28: Average Weekly Market Share by Fuel Type



APPENDIX E – RETAIL MARKET METRICS

Figure 29 - Comparison of Percentage of Sites Switched From RRO (Electricity) and DRT (Natural Gas)

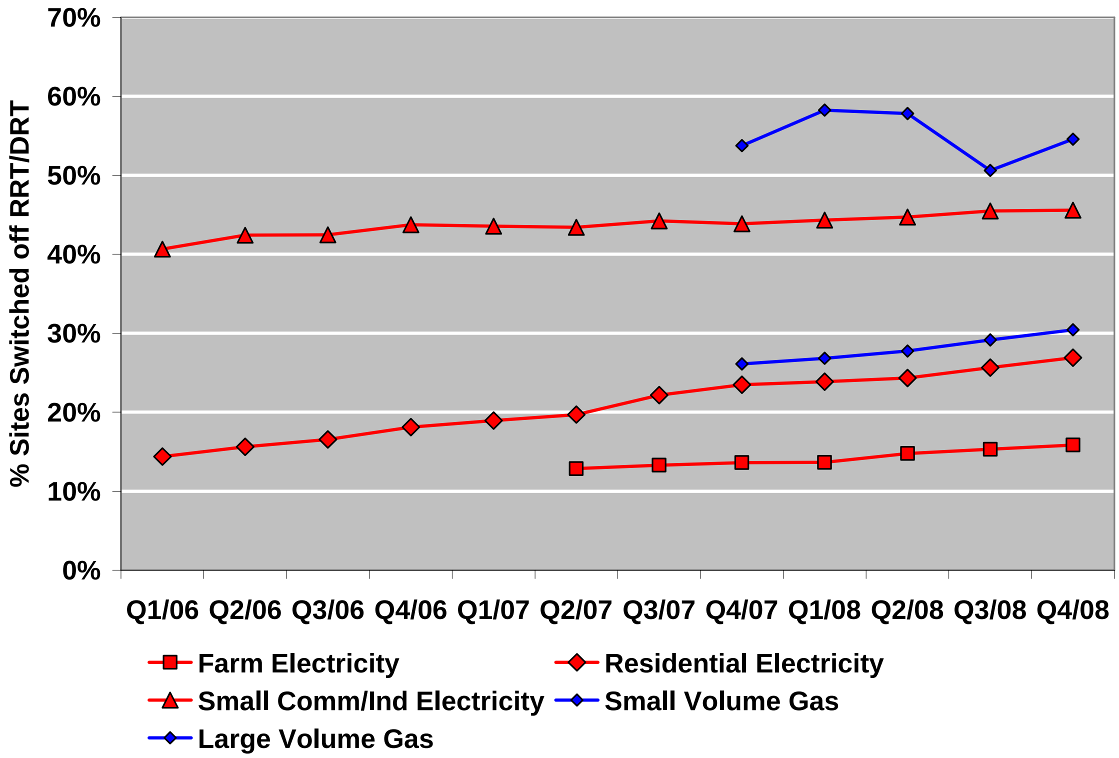


Figure 30 - Change in Market Shares in Residential Customer Class (Sites)

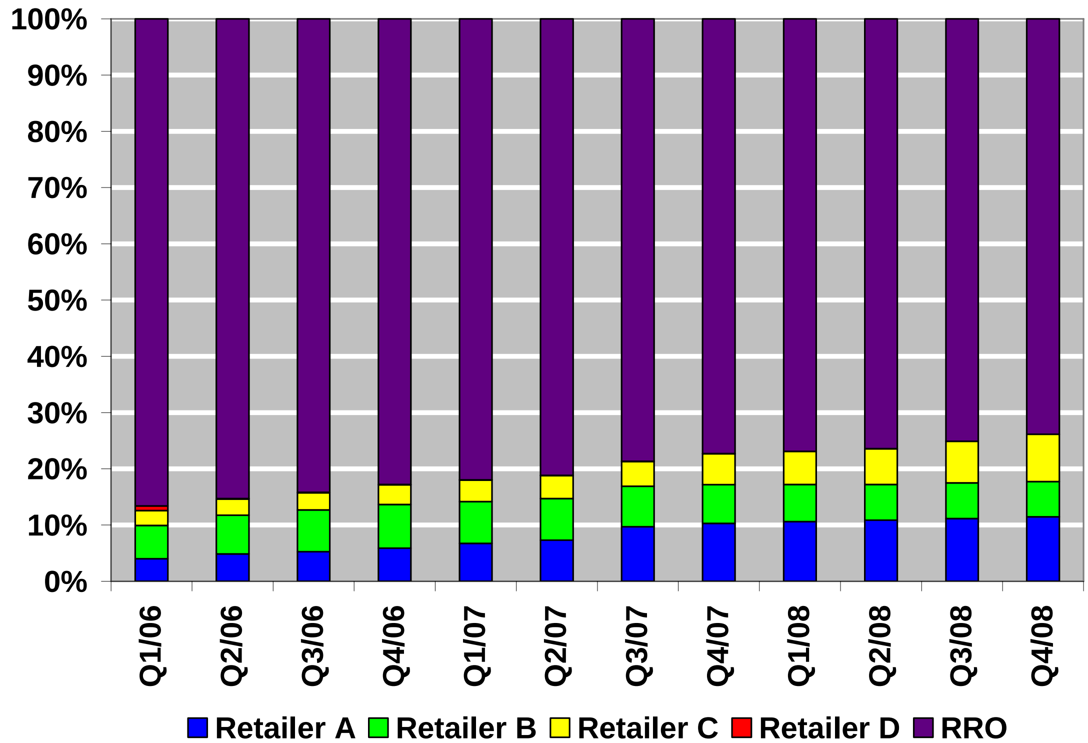


Figure 31 - Change in Market Share in Small Commercial/Industrial Class (Sites)

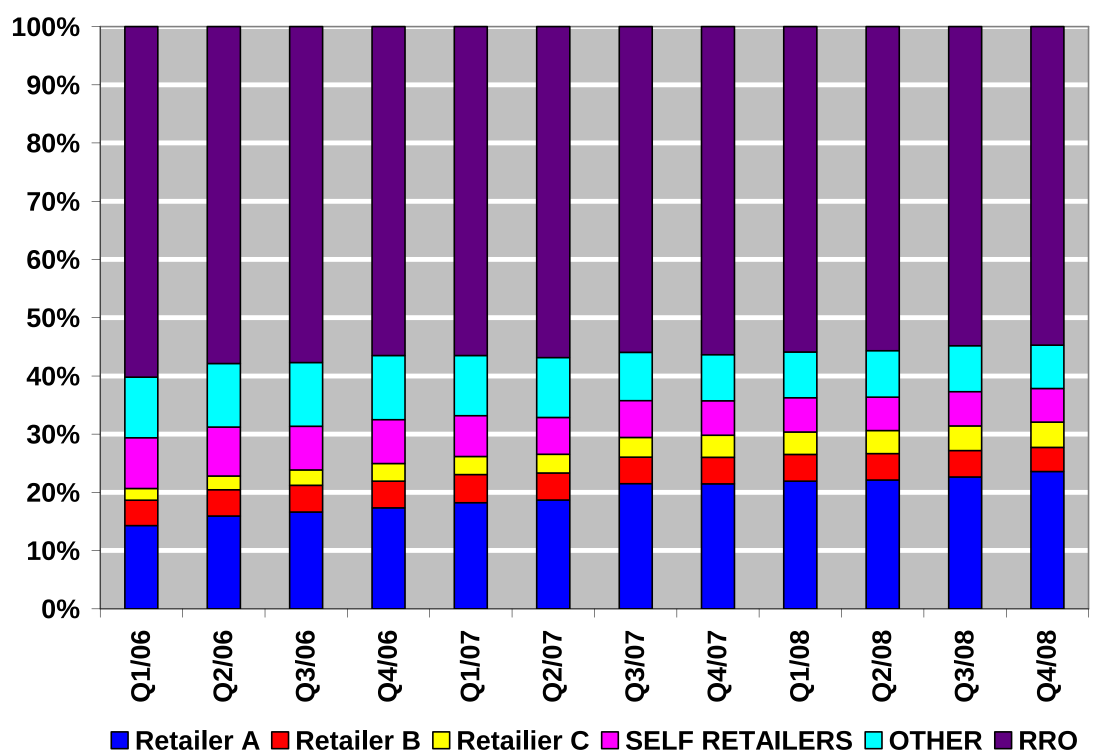


Figure 32 - Change in Market Share of Non-RRO Eligible Customer Class (Volume)

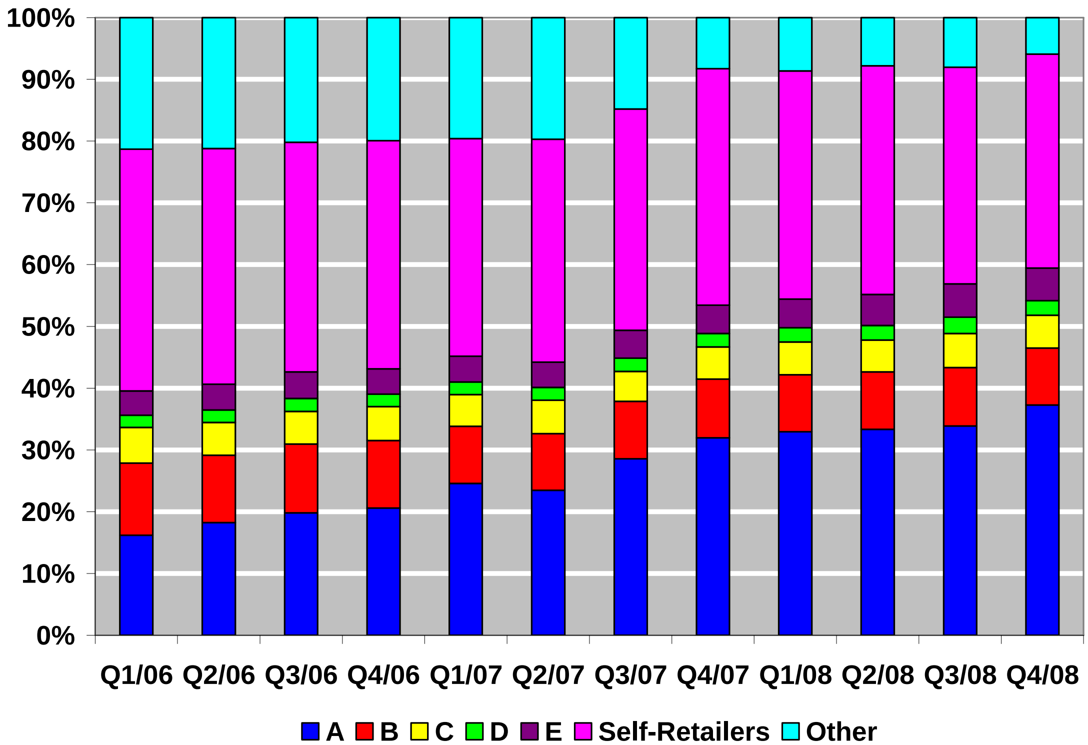


Figure 33 - Change in Market Share in Natural Gas Small Volume