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MSA REPORT

Quarterly Report

April – June 2005

29 July, 2005

MARKET SURVEILLANCE ADMINISTRATOR

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Market Highlights

- The average price of electricity in the Alberta wholesale market in Q2/05 was $51.44/MWh. This compares to $45.90/MWh in Q1/05 and $60.07/MWh for the same period a year ago. Year to date the average Pool price was $48.73/MWh at the end of Q2/05.

- The average implied market heat rate in Q2/05 was 7.4 GJ/MWh which was up from 7.0 GJ/MWh in the previous quarter but substantially down from 9.1 GJ/MWh in the same quarter a year ago.

- Production of generation outage reports produced by the MSA as an outcome of the TPG/IDP has now been phased over to the AESO and can be accessed via the AESO website. A load outage report will continue to be published by the MSA.

- Tie line economics appear to be improving. The proportion of deemed profitable to unprofitable imports on the BC tie line increased vs. Q1/05.

1 REVIEW OF THE WHOLESALE ELECTRICITY MARKET

1.1 Electricity Prices

Wholesale electricity prices in Q2/05 averaged $51.46/MWh which was up marginally relative to $45.90/MWh last quarter as shown in **Table 1**, although down from $60.07/MWh in the same quarter a year ago. **Table 1** and **Figure 1** also show that price volatility was up slightly over last quarter and up over Q2/04 as well. The month of June displayed the highest volatility over the quarter which can be attributed in part to maintenance outages at significant coal plants including Genesee 1 and Sheerness 2, reducing the base load component of the merit order, coupled with an offer curve that has tended to be largely bi-modal where the bulk of offered energy is priced at very low prices with the balance at very high prices with only a modest "shoulder" in the curve.

The price duration curves in **Figure 2** show that the distribution of hourly Pool prices in Q2/05 was quite similar to last quarter – in both Q1/05 and Q2/05, prices were above $50/MWh about 33% of the time. **Figure 2** also shows that in Q2/05, price excursions over $100/MWh were somewhat higher than in the last quarter.

Table 1 - Pool Price Statistics

	Average Price	On-Pk Price	Off-Pk Price	Std Dev[1]	Coeff. Variation[2]
Apr - 05	50.08	57.68	39.64	42.90	86%
May - 05	49.16	63.68	32.29	50.50	103%
Jun - 05	55.14	71.16	33.21	71.62	130%
Q2 - 05	**51.46**	**64.17**	**35.05**	**56.31**	**109%**
Jan - 05	50.24	54.73	45.02	66.94	133%
Feb - 05	42.67	48.49	34.90	33.65	79%
Mar - 05	44.78	49.60	38.10	36.69	82%
Q1 - 05	**45.90**	**50.94**	**39.34**	**48.65**	**106%**
Apr - 04	51.98	62.24	37.90	39.97	77%
May - 04	67.13	80.44	51.66	53.64	80%
Jun - 04	61.11	70.44	48.34	48.56	79%
Q2 - 04	**60.07**	**71.04**	**45.97**	**48.18**	**80%**

1 - Standard Deviation of hourly pool prices for the period

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

Figure 1 – Pool Price with Pool Price Volatility

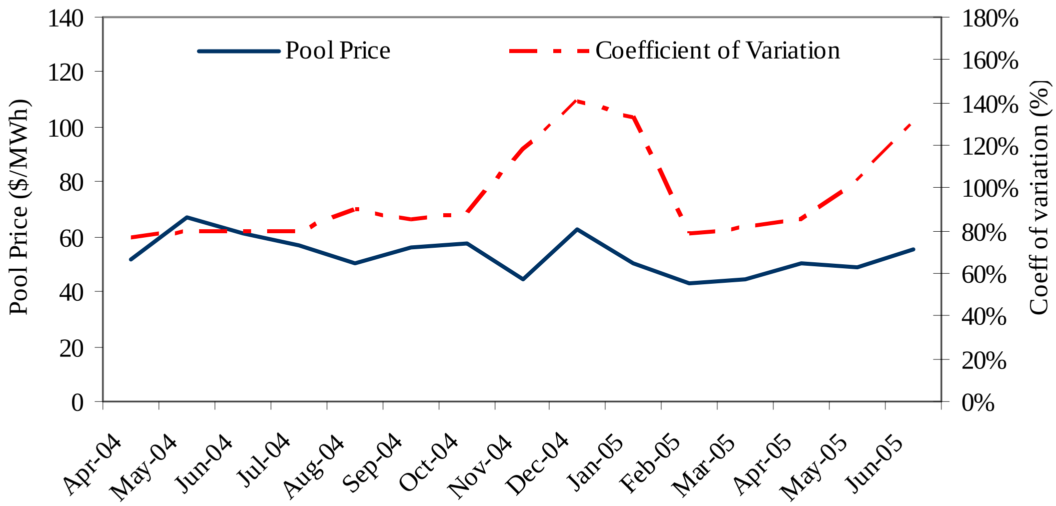
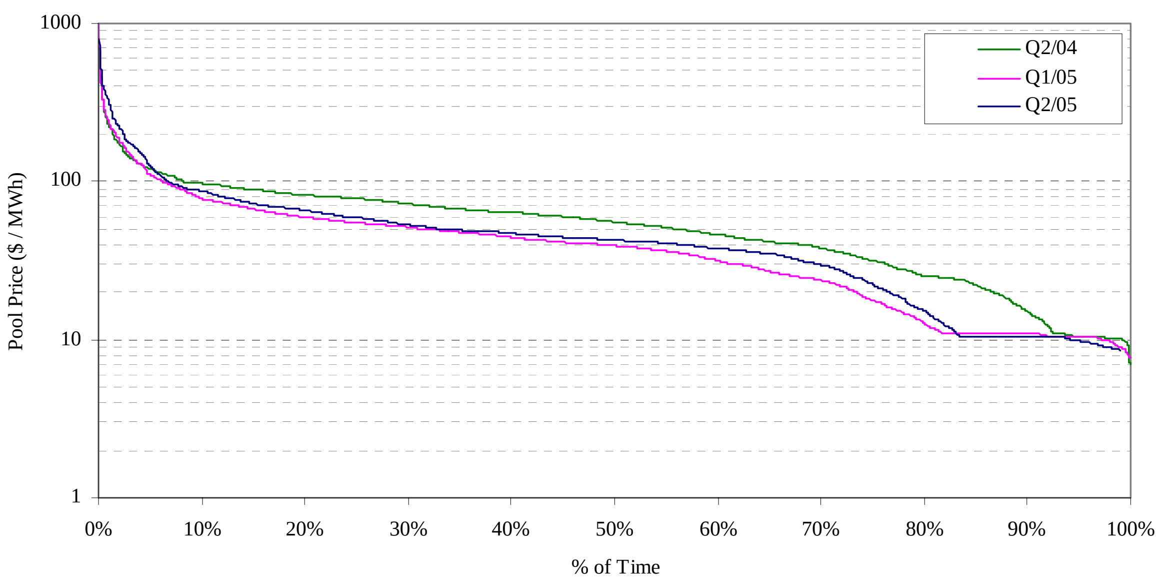


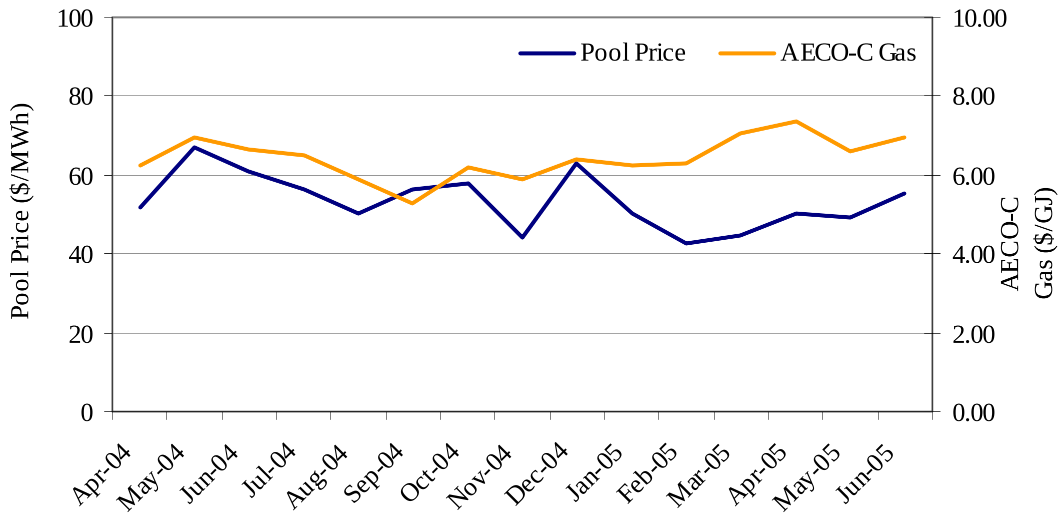
Figure 2 – Quarterly Pool Price Duration Curves



1.2 Natural Gas Prices

Alberta gas prices fluctuated in Q2/05 after moving higher at the end of the first quarter. The Q2/05 average gas price was $6.97/GJ vs. $6.54/GJ in the prior quarter. **Figure 3** shows the trend of Alberta gas prices together with Pool price over the last 12 month period. The first half of 2005 has seen Pool price driven to a greater extent by base load generators than by peaking units, thus based on the trailing 12 month correlation, there was no significant correlation between gas prices and the wholesale electricity price.

Figure 3 - Wholesale Electricity Price with AECO Gas Price



1.3 Price Setters

Figure 4 shows the five most frequent price setters in Q2/05 as compared to the previous quarter together with the weighted average price at which the respective parties set system marginal price (SMP). In Q2/05 the leading marginal price setter set SMP 21% of the time at a weighted average price of $13.60/MWh. In Q2/05, the 5 most frequent price setters were on the margin for a combined 76% of the time as compared to 81% of the time in the previous quarter.

Figure 4 - Price Setters by Submitting Customer (All Hours)

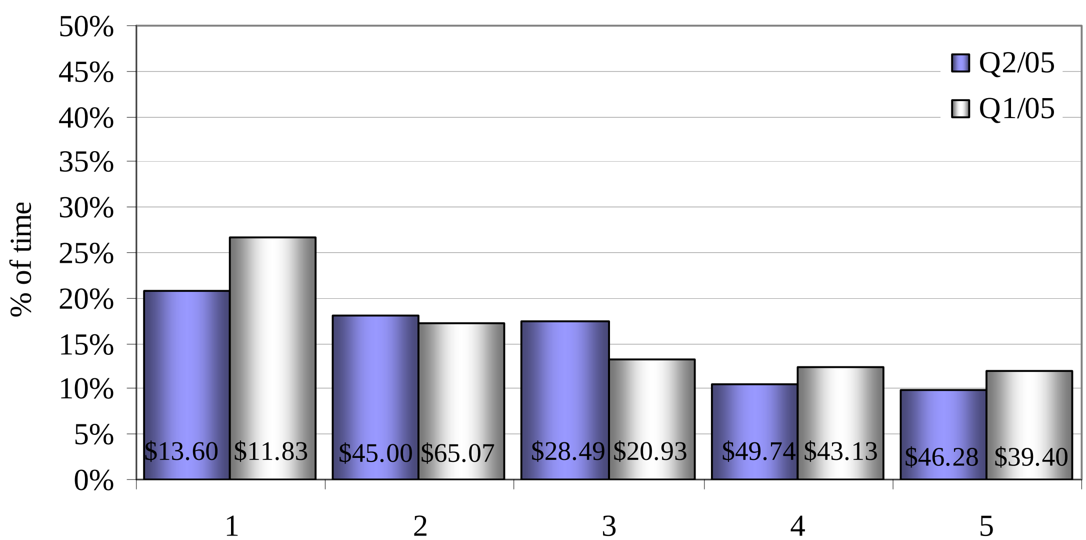
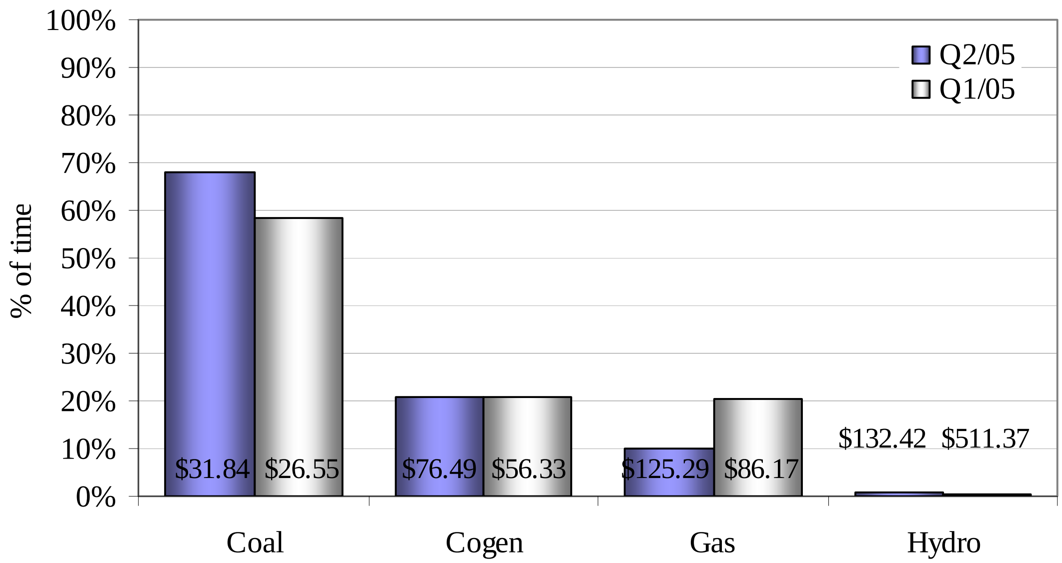


Figure 5 shows an equivalent distribution on the basis of generator fuel type. As in the previous quarter, coal units were the leading marginal fuel type in Q2/05, setting price 68% of the time – a new quarterly high water mark in the restructured market, at a weighted average price of $31.84/MWh. The relative absence of a normally prominent gas generator from the market and the addition of Genesee 3 to the system, contributed to coal being the dominant marginal fuel in Q2/05.

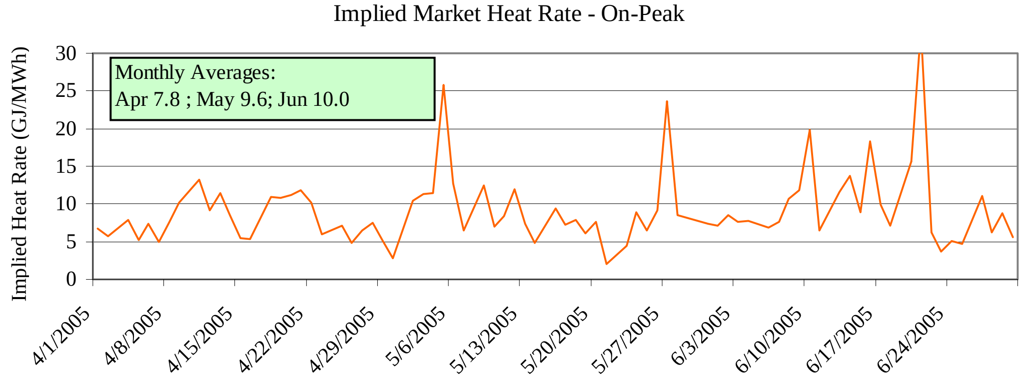
Figure 5 - Price Setters by Fuel Type (All Hours)



1.4 Implied Market Heat Rate

The implied market heat rate in Q2/05 averaged 7.4 GJ/MWh which was up marginally from 7.0 GJ/MWh for the previous quarter, but down noticeably from 9.1 GJ/MWh in Q2/04. **Figure 6** shows that market heat rates trended upward through the quarter on an on-peak basis while trending downward through the quarter on an off-peak basis. Overall, the weaker heat rate environment abated somewhat through the quarter with on-peak heat rates averaging 10.0 GJ/MWh in the month of June. Heat rate duration curves shown in **Figure 7** indicate that a combined cycle gas generator would have been able to meet or exceed its variable cost of gas about 39% of the time in Q2/05 – a moderate improvement over 30% of the time in Q1/05.

Figure 6 - Implied Market Heat Rates – Q2/05



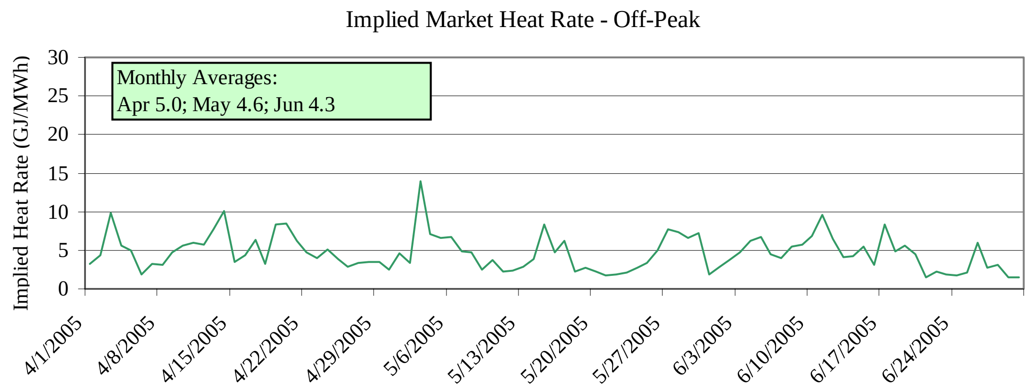
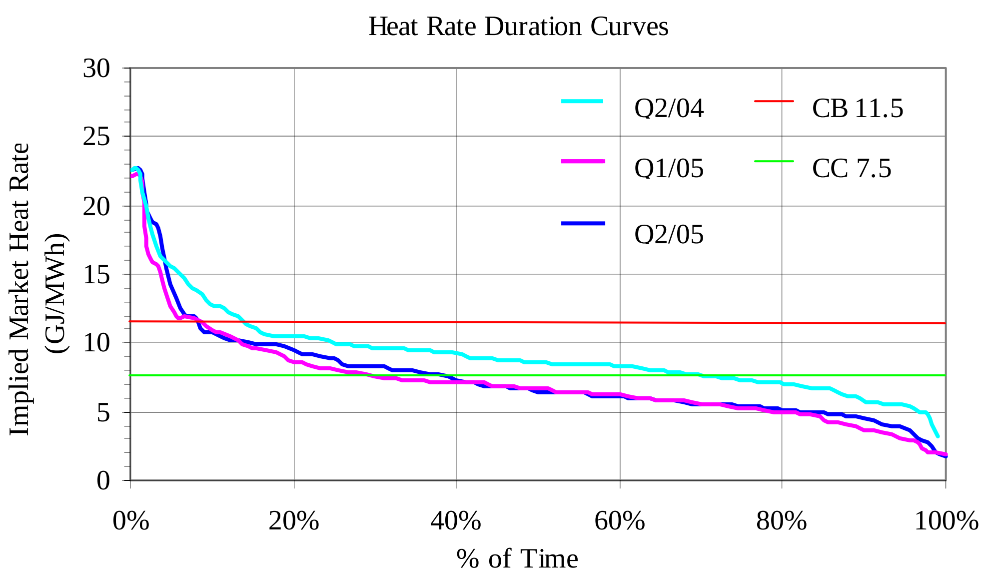


Figure 7 - Quarterly Heat Rate Duration Curves - (All Hours)



1.5 New AESO Rules

There were no significant changes to AESO rules implemented during Q2/05.

1.6 New Supply and Load Growth

No significant new generation was brought on line during Q2/05.

The monthly average hourly system demand in Q2/05 was:

April	7270 MW	+3.0% vs. Apr 2004
May	7292 MW	+3.8% vs. May 2004
June	7191 MW	-0.4% vs. June 2004

1.7 Net Revenues

In a 2004 report entitled "The Economics of New Entry" the MSA estimated the simulated cash flows and expected net revenues for an assortment of possible generation projects with common plant configurations. The projects modeled included:

- Base load coal-fired unit - 450 MW, located in the Central Alberta
- Peaking gas-fired combustion turbine – 47MW, located in the Northern portion of the province
- Combined cycle plant – 250 MW, located in Southern Alberta

All aspects of the costs and performance characteristics were 'genericized' to represent a *typical* new project rather than any specific unit. This assessment concluded that prices in 2002 and 2003 were not sending a signal to 'build' to would-be generators.

Updated Analysis

For the purpose of an update to the 2004 assessment we have selected identical plant configurations and identical cost assumptions.[1] We recognize that some capital and operating costs have changed since 2003, as have loss factors. In the interests of consistency, we have kept these assumptions the same as in our 2004 report. As in the 2004 report, it was assumed that all net revenue was applied to the payback of the capital cost. No assumptions were made regarding financing for any of the units as these costs are felt to be unique to each new generation owner. Factors not included in cash flows estimates:

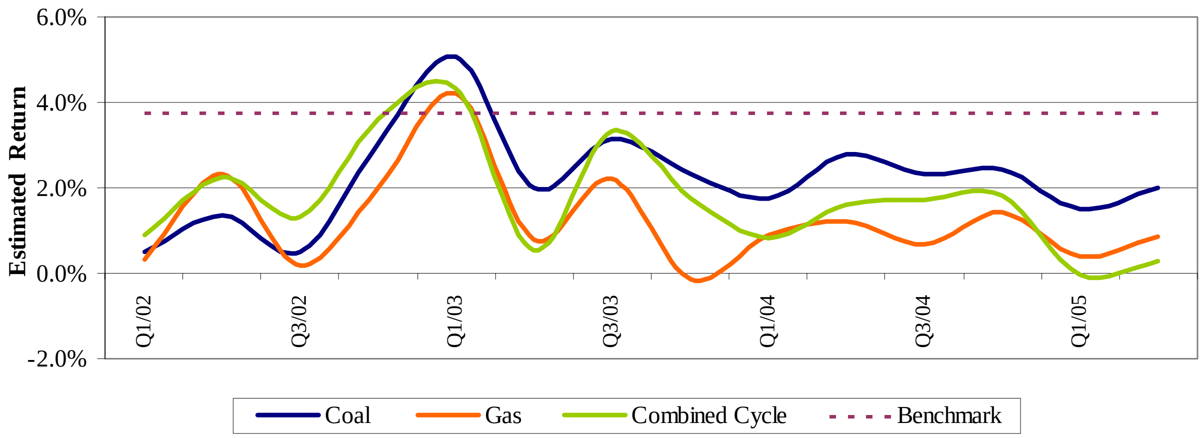
- Provision of Ancillary Services
- Transmission Must Run (TMR) Contracts
- IBOC and LBC-SO Contracts

[1] A full list of assumptions is contained in the MSA's 2004 report 'The Economics of New Entry'.

These three factors have the potential to increase net revenues of the units and as a result would likely increase the rates of capital payback. As such, results provided in this analysis may be somewhat conservative and should be considered directional in nature.

Estimated cash flows were simulated hourly from 2002 to June 2005 using hourly Pool prices and daily AECO-C gas prices (where applicable). Quarterly capital cost repayment percentages for the three unit types for the period analyzed are presented in **Figure 8**. A benchmark return consistent with one likely required by a merchant generator was determined to by around 15% annually or 3.75% per quarter. Values below this benchmark would be considered unattractive, suggesting the current Alberta market price was too low to justify new generation additions.

Figure 8 - Estimated Net Revenues by Quarter



With strong market prices in late 2002 and early 2003 the returns would have been well above the benchmark making new construction on generation facilities attractive for all three projects. However, during 2004 and 2005 year to date, lower market prices and higher gas prices resulted in rather unappealing financial returns for the gas fired units as stand alone units and even the coal fired project was found to be below the benchmark the majority of the time. It should be noted that over the last 18 months there have been substantial changes to the province's generation fleet with both additions and retirements occurring. Nevertheless, overall returns continue to remain at a level that would not entice significant investment in new generation facilities.

Table 2 - Estimated Annual Return

Reference Year	Unit		
	Coal	**Gas**	**Combined Cycle**
2002	5.40%	4.80%	8.10%
2003	12.50%	7.10%	9.90%
2004	9.30%	4.20%	5.90%
Average	**9.07%**	**5.37%**	**7.97%**

Table 2 shows that on an annualized basis, the coal unit continues to be the best performer in a market with high gas prices and lower realized pool prices. The gas "peaker" unit that benefits from price spikes appears to be the least likely new generator to enter the market given estimated returns over the last three years averaging less than 6 %.

1.8 Imports, Exports, and Prices in Other Electricity Markets

Activity on the interties between Alberta and BC and Saskatchewan is a significant part of the operation of the Alberta electricity market. **Table 3** summarizes the activity on the tie-lines for Q2/05.

Table 3 - Tie Line Activity Q2/05

	BC			Saskatchewan			Overall		
	Imports (MWh)	**Exports (MWh)**	**Net Imports (MWh)**	**Imports (MWh)**	**Exports (MWh)**	**Net Imports (MWh)**	**Imports (MWh)**	**Exports (MWh)**	**Net Imports (MWh)**
April	75,532	*144,177*	(68,645)	*31,090*	*1,180*	29,910	106,622	145,357	(38,735)
May	*107,463*	*72,928*	34,535	*36,423*	*1,003*	35,420	143,886	73,931	69,955
June	*145,899*	*63,870*	82,029	*35,408*	*234*	35,174	181,307	64,104	117,203
Total	**328,894**	**280,975**	**47,919**	**102,921**	**2,417**	**100,504**	**431,815**	**283,392**	**148,423**

Alberta was an overall importer for the quarter with 148,423 MWhs of net imports. Import volumes were dominant on both sides of the province with 47,919 MWhs net imports from BC and 100,504 MWhs of net imports from Saskatchewan for the quarter. Export volumes were notable on the BC tie line during the early part of the quarter and tapered as June approached. For the most part, BC exports occurred during the off-peak hours when Alberta prices tend to be relatively low. For operational reasons in Alberta, export capacity on the BC tie line is often not available during on-peak hours.

The Saskatchewan tie-line was used primarily for imports during Q2/05 with minimal exports leaving Alberta. With the opening of the new MISO markets to the east of Saskatchewan, many exporters have found it challenging to decipher the new market structure in order to effectively move power out of Alberta and into the eastern US via the Saskatchewan interconnection.

Over the course of the quarter, Alberta exported over 283,000 MWh and imported over to 430,000 MWh of electricity. The large amounts of imports could be attributed to relatively inexpensive power available to the province and high levels planned outage for base load generation. These fundamental factors were likely influenced by mild rainy weather and significant levels of hydro power as a result of the accelerated run off during the quarter.

Figure 9 shows the relative market shares of importers and exporters in Q2/05. The figures include imports and exports on both the BC and Saskatchewan tie-lines. Both importing and exporting were dominated by one market participant with a 45% market share of imports and an 89% market share of exports. The second largest importer lost some market share (down to 17% from 24% last quarter). The market shares for the bulk of participants remained generally constant on the export side with the only notable change being the second largest exporter last quarter dropped off and only exported approximately 1% in Q2/05 versus 9% in Q1/05.

Figure 9 - Market Share of Importers and Exporters, Q2/05

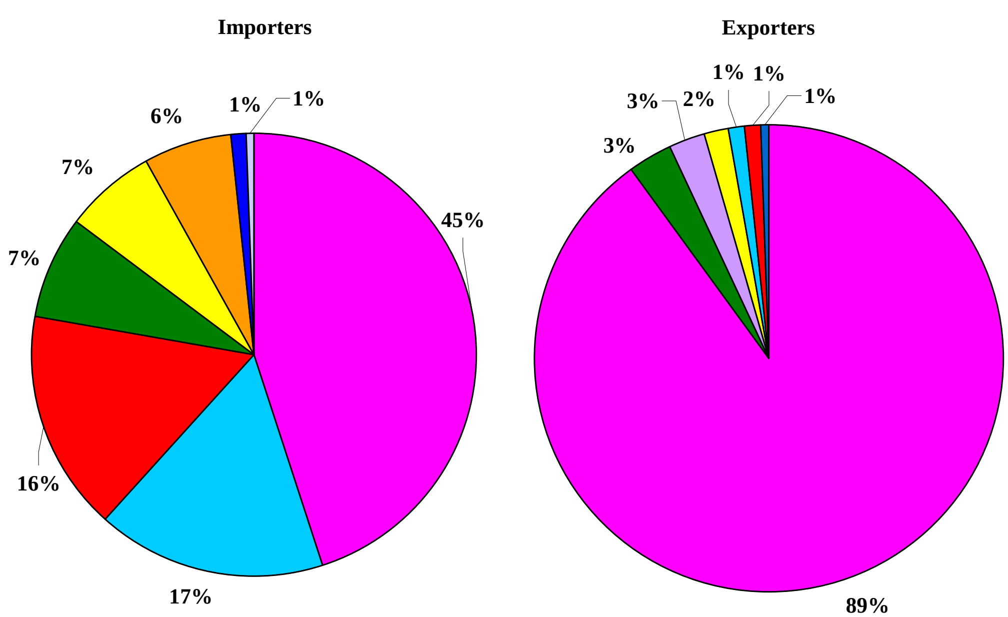
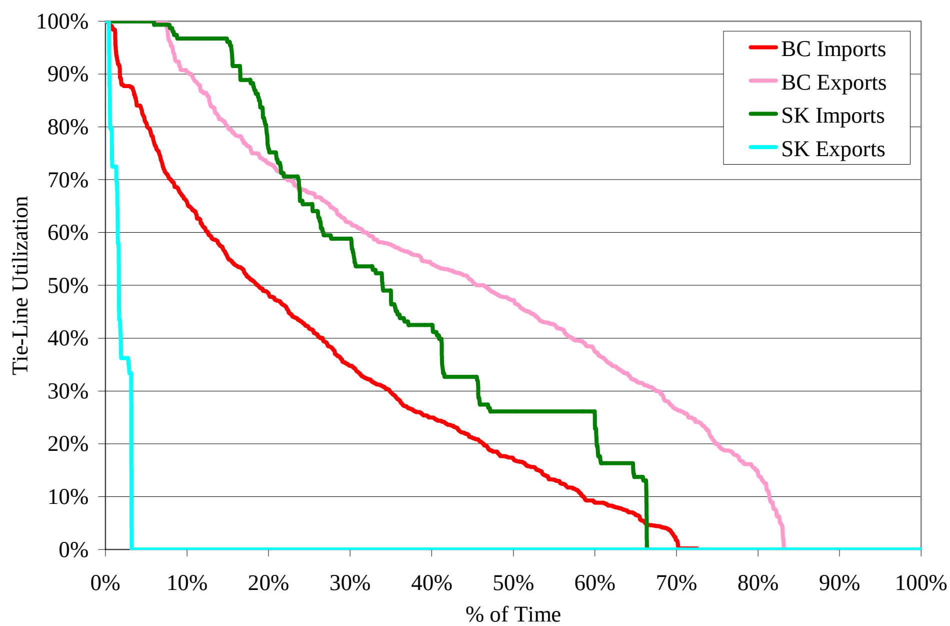


Figure 10 shows a duration curve of tie-line utilization in Q2/05 as a function of posted available transfer capability (ATC)[2]. The figure shows that there is often some unutilized capacity available on both of the tie-lines. The BC export ATC was the most effectively utilized in Q2/05 as there was some volume of energy being exported from Alberta to (or through) BC approximately 83% of the time that the line was available. The BC import ATC was less used coming in at 71% utilization. The Saskatchewan import capacity was better utilized compared to Q1/05 when it was by far the most underutilized during that quarter. In Q2/05 it was 66% utilized when in Q1/05 it was around 27% utilized. The least utilized for this quarter was the SK export tie coming in at under 4% utilization but it should be noted that there was significant maintenance performed on that interconnection which likely reduced its overall utilization.

Figure 10 – Tie-Line Utilization, Q2/05



It is not reasonable to expect all of the tie-lines to be full, or even in use, 100% of the time. A number of factors including (but not limited to) transmission access, market price and the market position of each participant contribute to determining whether or not it is profitable to make use of the available tie-line capacity.

Activity on the tie-lines can be highly dependent on the Alberta market price. **Figures 11 and 12** plot total monthly imports with monthly weighted average price of import volumes and total monthly exports with

[2] ATC is the maximum amount of energy which can be moved across the tie-line in any given hour. For example, if the ATC of an intertie for an hour was 500 MW and only 200 MW flowed across that line in that hour, the utilization would be 200/500 or 40%. ATC is posted on the AESO website and varies on an hourly basis.

monthly weighted average price of export volumes respectively for the April 2004 through June 2005 period.

Figure 11 - Imports and Weighted Average Price of Imports

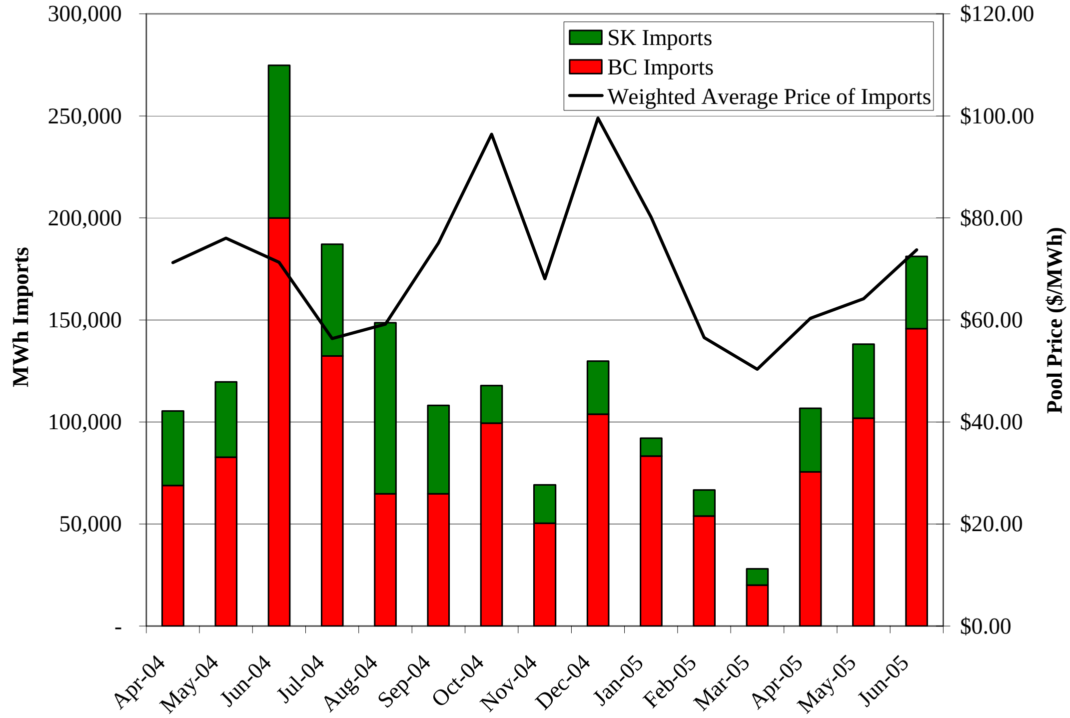
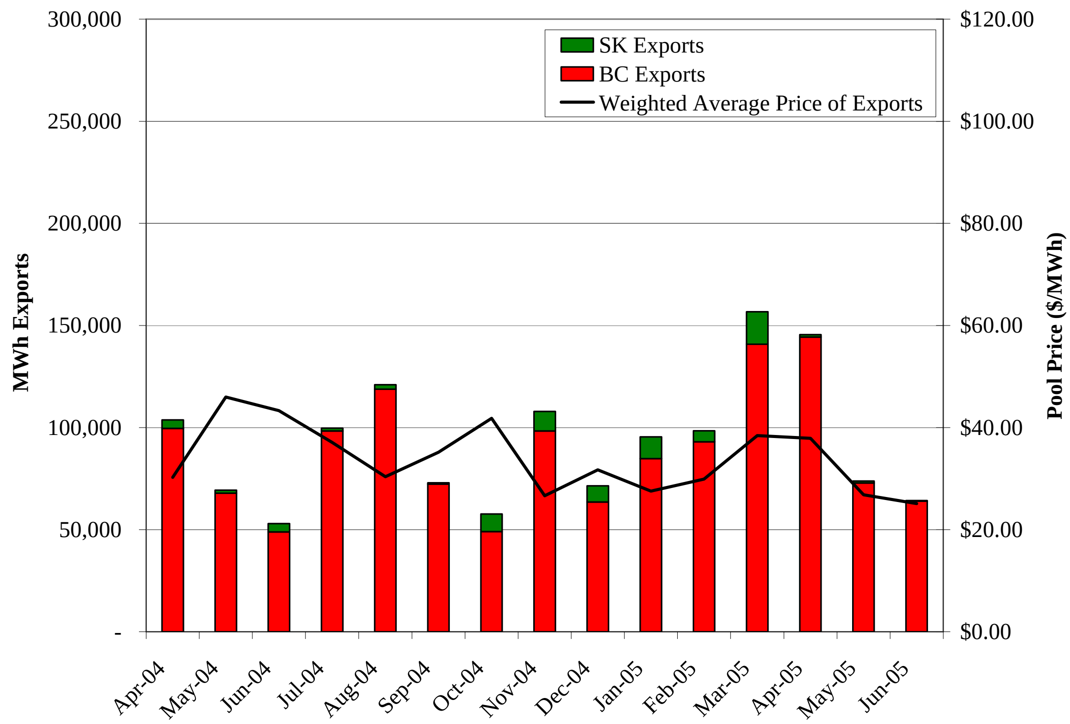


Figure 12 – Exports and Weighted Average Price of Exports



Over the quarter, import volumes responded fairly well to Pool prices on a monthly average basis. One might expect the weighted average price received by importers to be greater than the on-peak average Pool price, which was the case through Q2/05. For exports, it might be expected that the weighted average price paid by exporters would be lower than the off-peak average Pool price and this also was the case in Q2/05.

Prices in other markets have an impact on the economics of moving electricity into and out of the province. Although neither of Alberta's neighbors operates a competitive electricity market, electricity is often moved through these areas and into adjoining markets. **Figures 13 and 14** show monthly average on-peak and off-peak price indices for the Mid West ISO (MISO) and Mid-C in the Pacific Northwest which are compared to Alberta Pool price. All prices are in Canadian dollars and have been converted at the daily exchange rate.

Figure 13 - On-Peak Prices in Other Markets

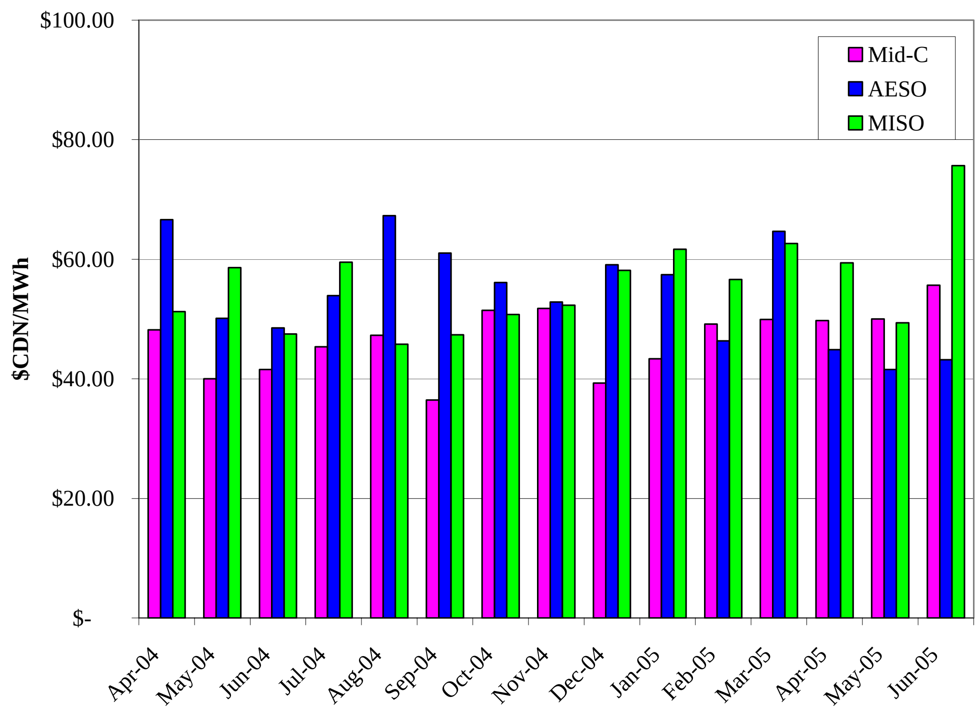
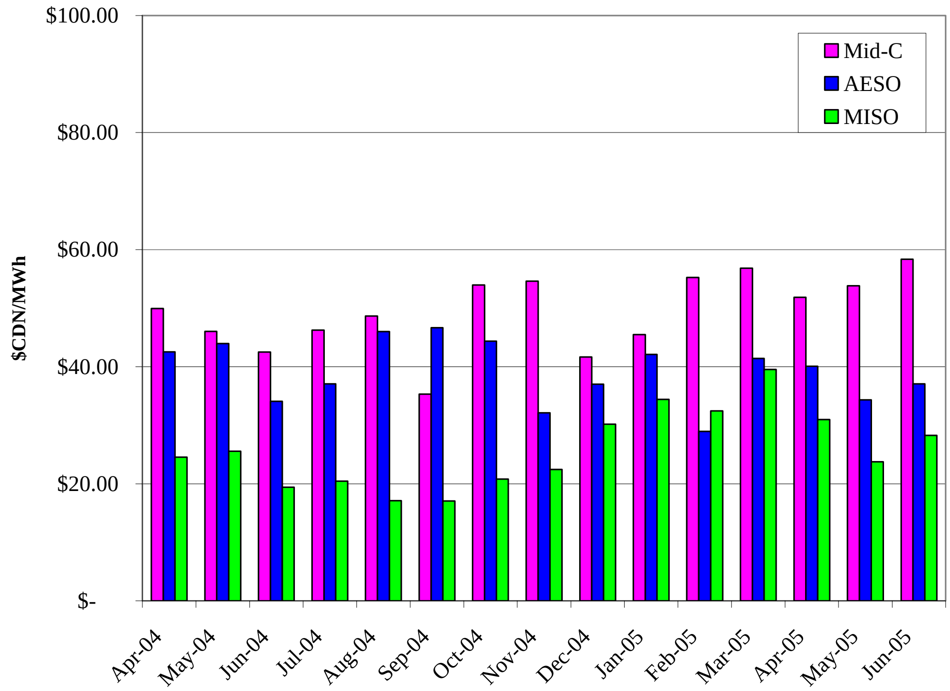


Figure 14 - Off-Peak Prices in Other Markets



On-peak Prices for MISO (specifically Minnesota Hub reference point) were above Pool prices during the quarter which would make it attractive to economically export from Alberta to MISO. On-peak prices at Mid-C were also higher than Pool prices through the quarter.

Alberta prices were generally lower than Mid-C prices and slightly higher than MISO prices in the off peak time frame. These price differentials tend to support off-peak exporting to Mid-C and importing from the MISO areas[3]. This expected flow of power based on price signals in neighboring jurisdictions is often reflected in the actual import/export activity observed over the last quarter.

The MSA continues to closely monitor the tie line for flows that are apparently contradictory to the economic direction implied by the hourly Alberta – Mid C differential, adjusting for transmission charges and line losses. Scatter plots in **Figure 15** show BC tie line net flows plotted against implied profitability for Q2/05. Chart (b) removes Powerex volumes due to the influence of storage on their fundamentals; chart (c) is a smaller scale version of chart (b). The figure indicates a marked

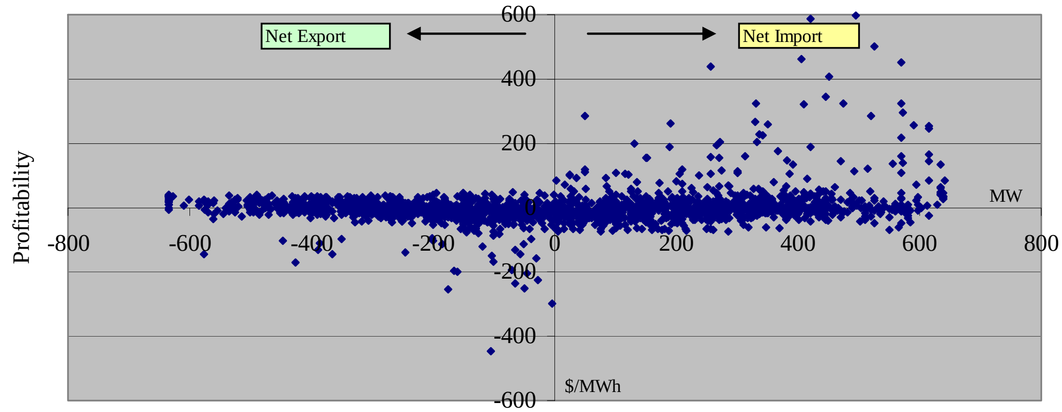
[3] The difference in the price at which energy can be bought and sold gives an indication of the economically correct direction for energy to be moving across the tie-line. For example, if the Pool price in Alberta is $50/MWh and the price at MID-C is $100/MWh, it would be most economically efficient to buy energy in Alberta and sell it at MID-C (i.e. exporting). Energy being imported during that price scenario would be seen to be economically inefficient use of the tie-line.

improvement in the ratio of deemed profitable imports to unprofitable ones however no noticeable change in export profitability in Q2/05.

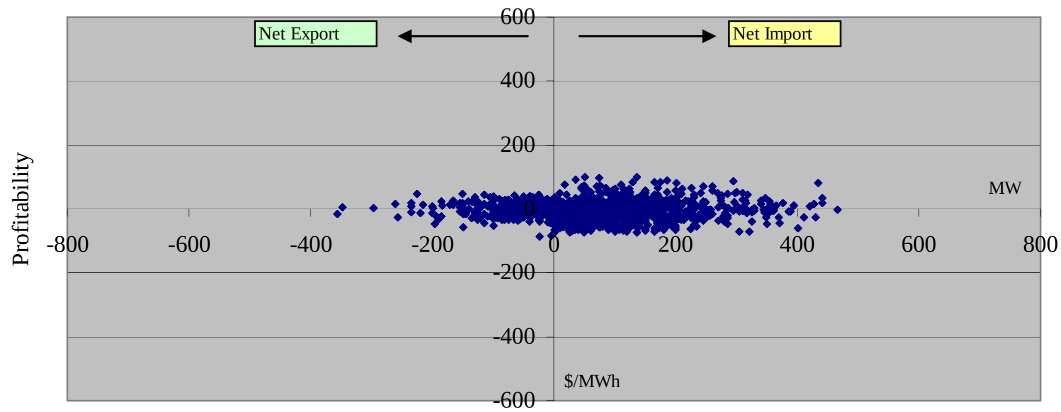
Over the course of Q2/05, the MSA has expanded on its paper published in January wherein it reviewed the economics of imports and exports on the tie line. During this time the MSA has had the opportunity to consider and test with market participants various principles which should help guide participants in their import and export decisions. In assessing their tie line strategies against the suggested principles, the market participants will have an opportunity to assess their conduct against the standard set in Section 6 of the EUA. As a result of these discussions with the major tie line players, the MSA has already observed some improvement in economics of imports and exports and expects this to continue. For a description of the principles referred to above, please see the MSA Notice to Participants entitled Intertie Conduct.

Figure 15 – Q2/05 Implied Tie-line Economics vs. Net Flow

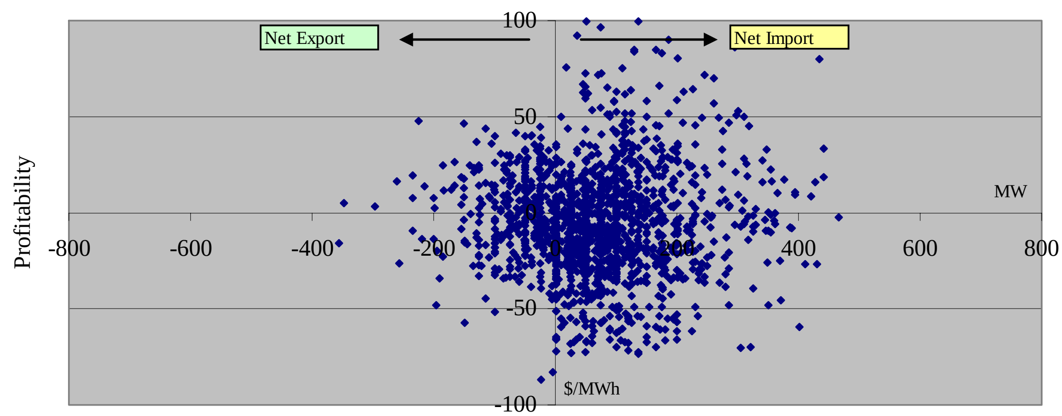
(a) All Firms



(b) Excluding Powerex



(c) Excluding Powerex



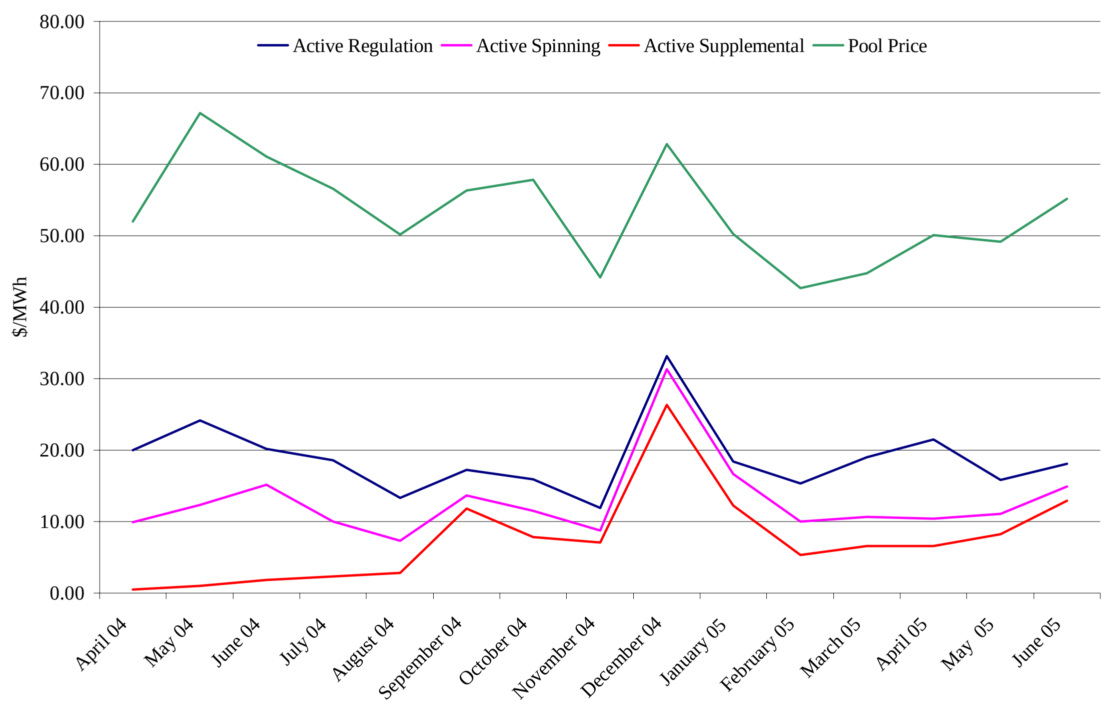
1.9 Ancillary Services Market

Active Reserves Market

Figure 16 shows monthly average settlement prices for each of the three active reserve products on a trailing 15 month basis, which includes both exchange procured volumes and over the counter volumes.

Active reserve settlements trended modestly upward in Q2/05 reflecting the overall trend in average Pool prices although active regulating reserve settlements fell from April to May. This suggests more competitive pressure in the active regulating market in May as less coal capacity was offering inexpensive reserves as was the case in April.

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



Standby reserves, unlike active reserves, are not indexed to Pool price. Standby reserves have a two part pricing mechanism similar to options. Firstly, the supplier is paid a premium which is the guaranteed fee which entails the AESO having a call on the product. Secondly, suppliers are paid an activation price which is paid only in the event that the reserve contract is activated and the reserve is delivered. As shown in **Figure 17**, Standby premiums overall trended sharply upward in Q2/05 although regulating premiums fell back $1.25/MWh on average in June. The rise in standby premiums through Q2/05 was likely due at least in part to a corresponding decline in activation rates through the period, which prompted sellers to raise premiums in their offers.

Figure 17 - Standby Premiums - All Markets (Watt-ex and OTC)

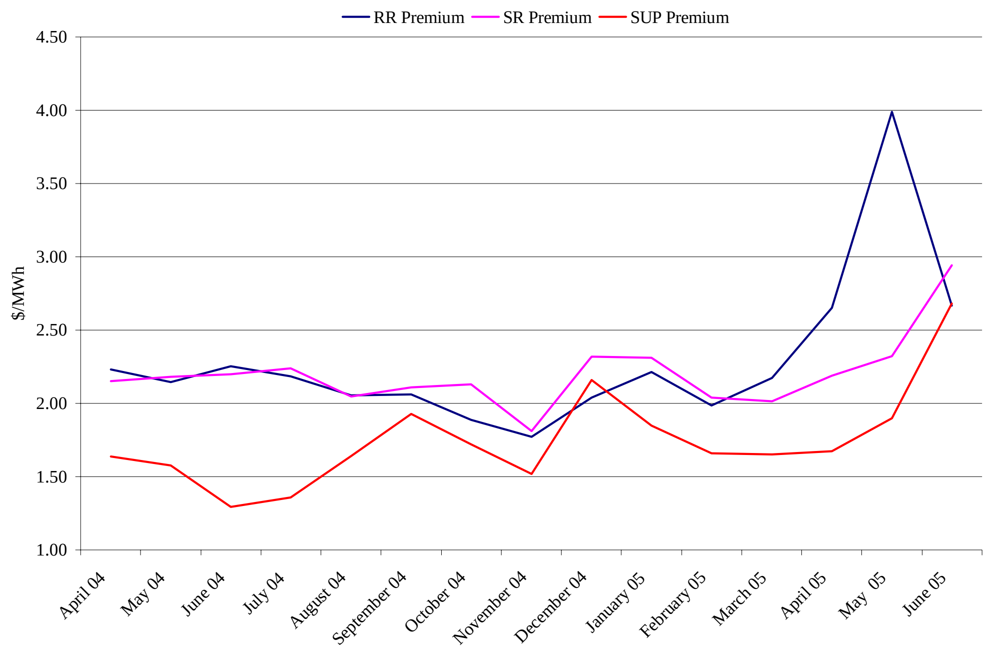


Figure 18 shows activation prices for standby reserve products including Watt-ex and OTC procured volumes. Activation prices trended upward through Q2/05 although for standby regulating, activation prices fell back from May to June.

Figure 18 – Activation Prices – All Markets (Watt-ex and OTC)

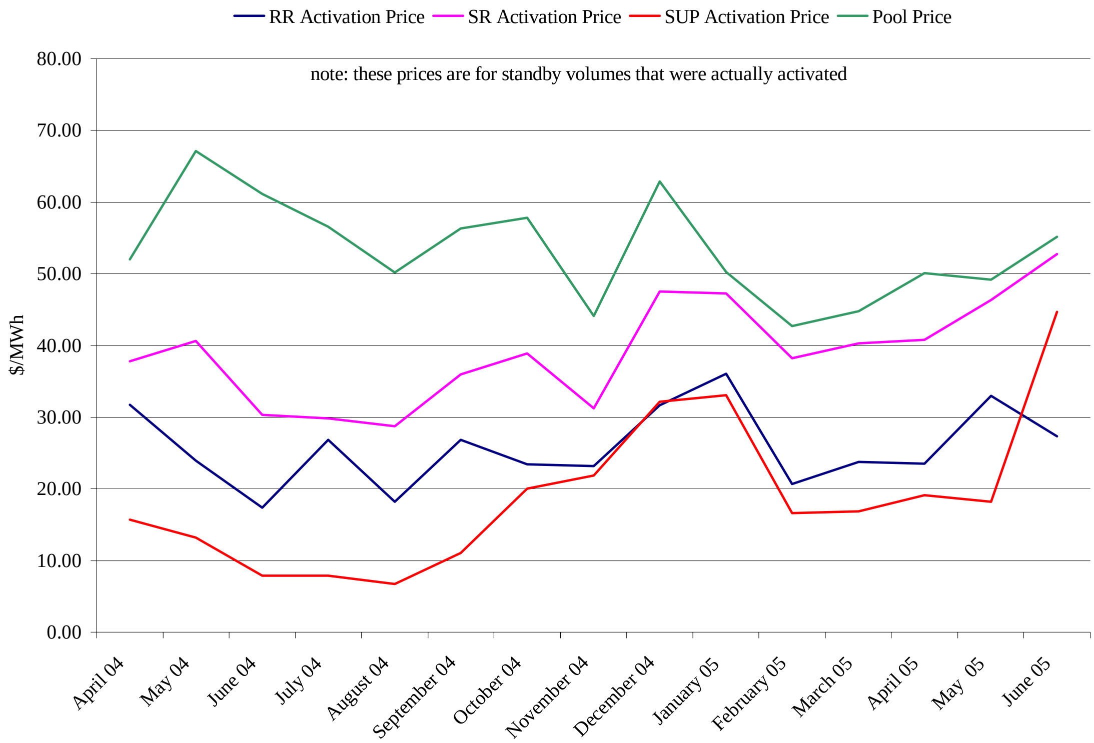
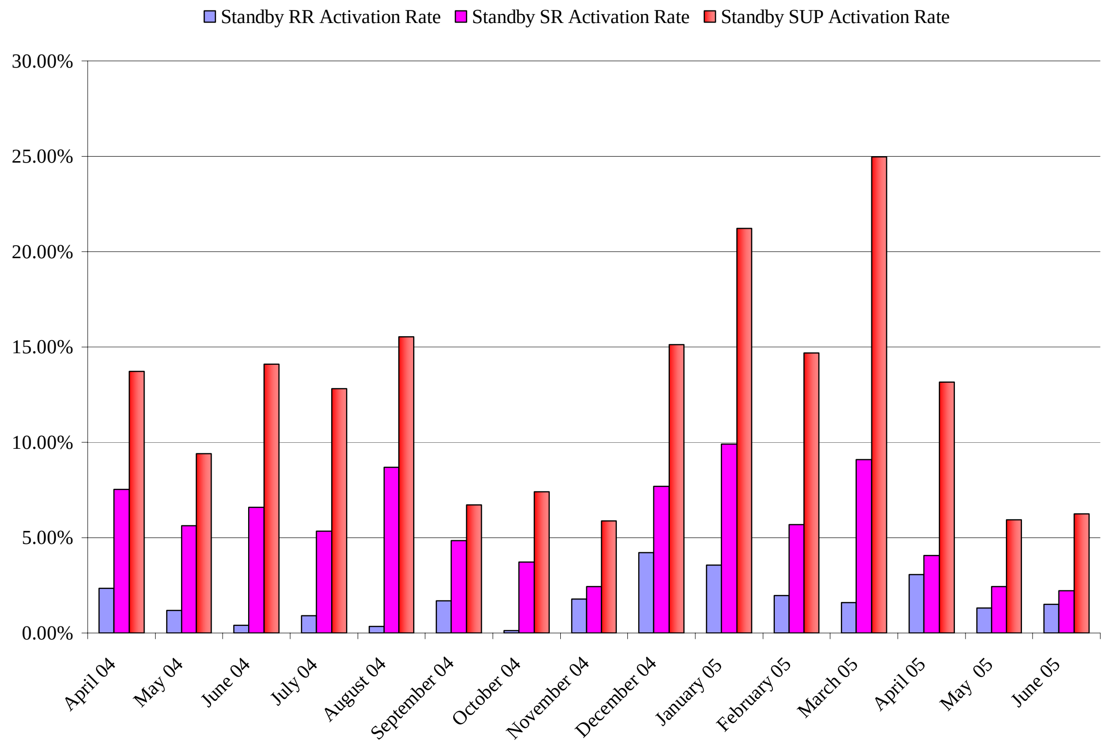


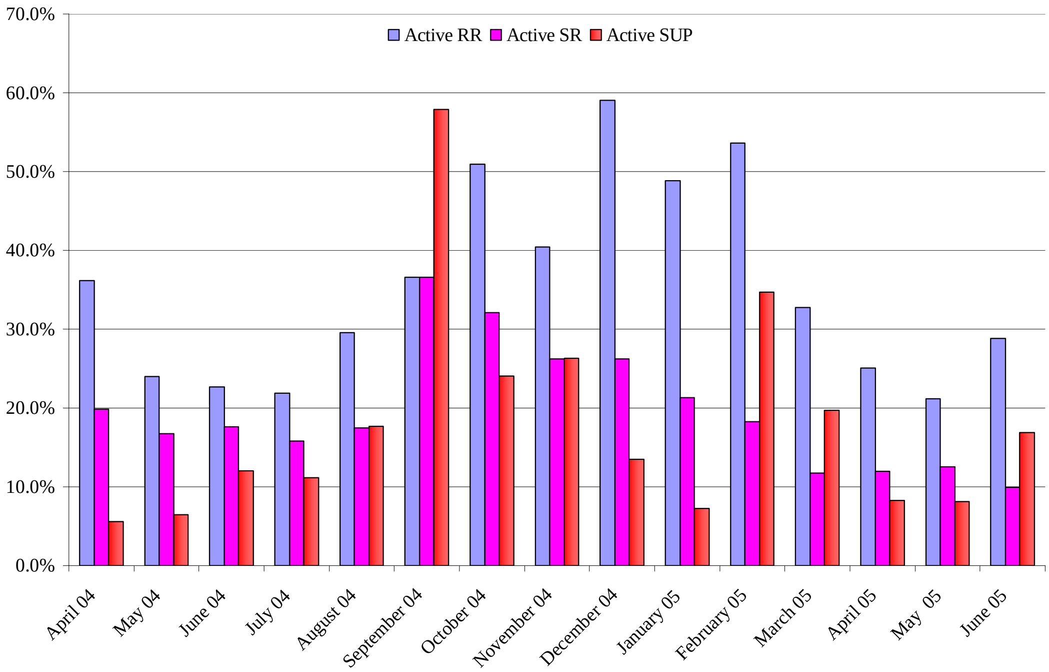
Figure 19 shows that activation rates for standby reserves has trended downward through Q2/05. Standby supplemental reserves tend to show more dramatic changes in activation rates due to the small relative size of the market. A smaller proportion of standby is typically procured relative to active – about 25% on average. This proportion is approximately 50% in the case of spinning reserves and about 75% for regulating reserves.

Figure 19 - Standby Activation Rates



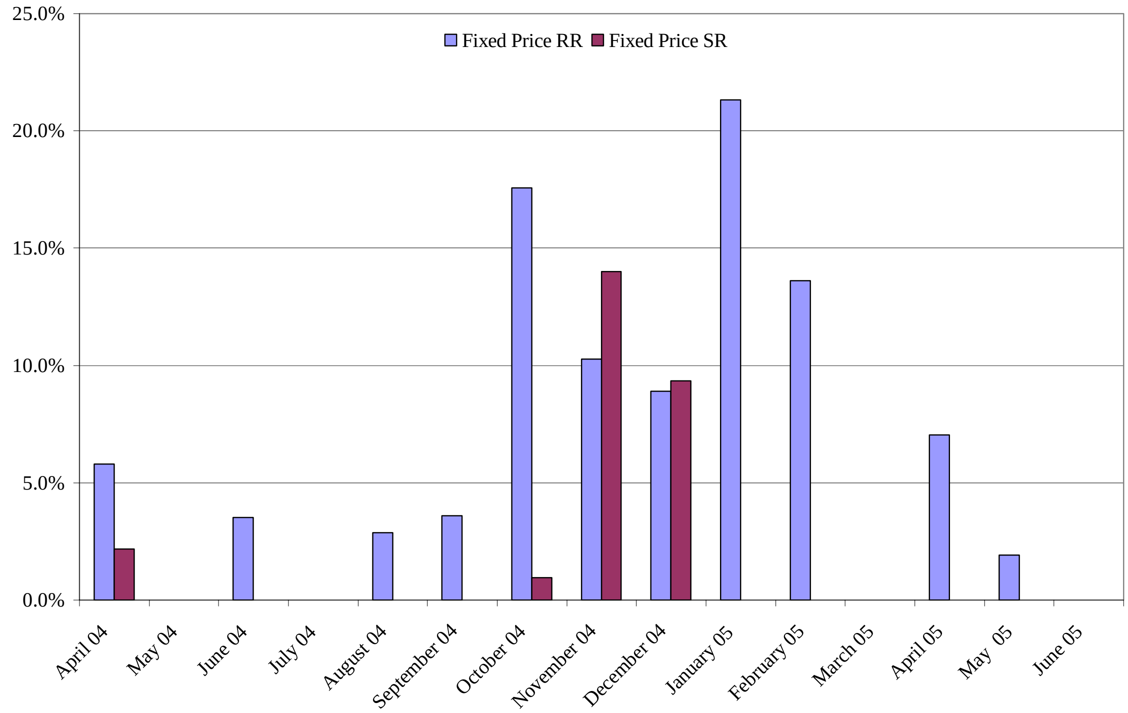
OTC procurements of active reserves fluctuated through Q2/05 with no clear trend apparent, however, as shown in **Figure 20,** OTC procurements were down substantially from the previous two quarters. OTC procurement percentages are influenced by the AESO's procurement strategy and in the case where a longer term reserve contract may be transacted OTC. The MSA continues to monitor levels of OTC procurement relative to exchange traded volumes and the level of disclosure with respect to OTC procured volumes.

Figure 20 - OTC Procurement as a % of Total Procurement



Fixed price procurements as shown in **Figure 21** were not prominent in Q2/05 as there were no regulating volumes similar to Q1/05 and fixed spinning reserve contracts were modest relative to levels in late Q4/04 and early Q1/05. This indicates there was not a strong desire on behalf of market participants to lock-in prices of reserve transactions in Q2/05.

Figure 21 - % of Active Regulating and Spinning Purchased at Fixed Price



Figures 22, 23, and 24 show settlement prices for active regulating, spinning, and supplemental reserves, overall, and divided into exchange traded volumes and OTC procured volumes. OTC procured volumes tend to be priced marginally higher than exchange traded volumes since OTC includes non-standard contracts which often command a market premium. In Q2/05, OTC procurements were substantially higher in the case of spinning reserves and higher but less so in the case of regulating reserves. It is important to note that while OTC settlements in these cases were greater, the influence on overall settlements was quite modest due to the relative weighting of procurements towards Watt-ex. This is demonstrated in **Figures 22, 23, and 24** in the proximity of the overall settlements line to the Watt-ex settlement line.

Figure 22 - Active Regulating Reserve Settlement by Market

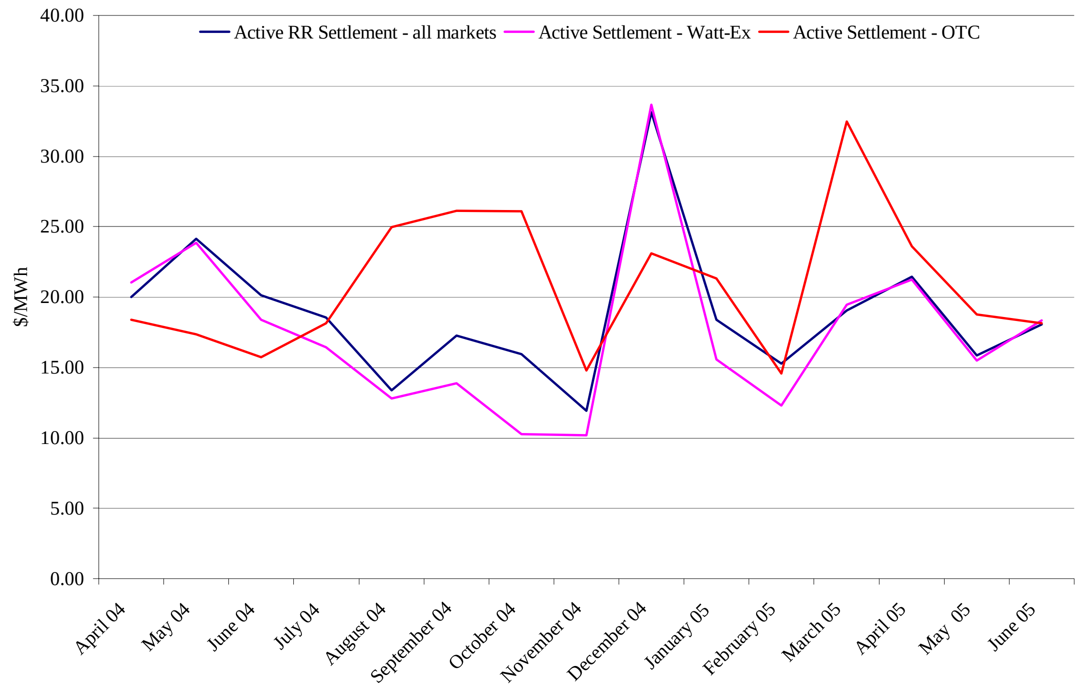


Figure 23 - Active Spinning Reserve Settlement Price by Market

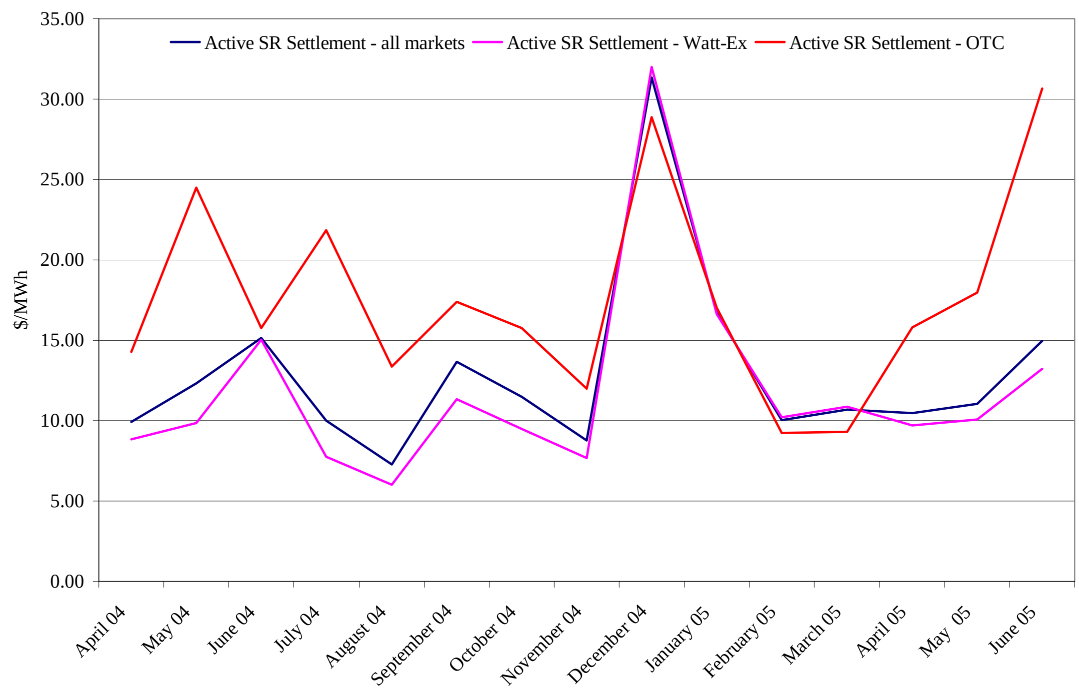
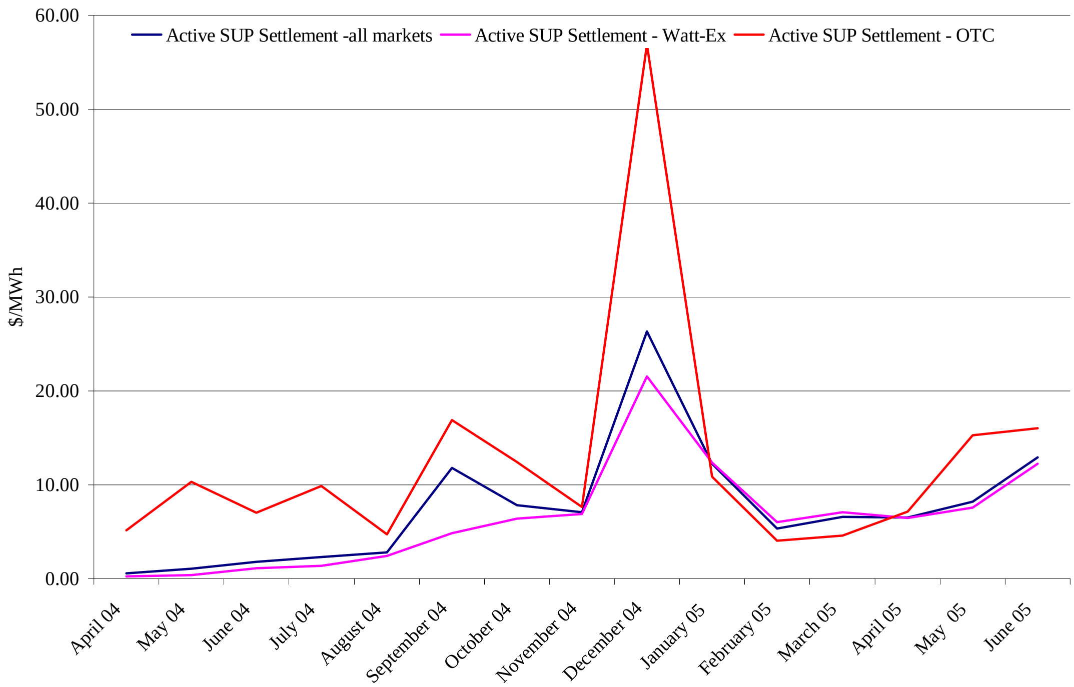


Figure 24 - Active Supplemental Reserve Settlement Price by Market



Figures 25, 26, and 27 indicate the market share division for reserve products by fuel type of the reserve provider. Market share for regulating reserve in Q2/05 fluctuated between coal providers and gas providers with hydro remaining essentially constant. In April, coal comprised 28% of regulating reserve volumes which was a 12 month high.

In spinning reserves, gas share trended upward through Q2/05 at the expense of hydro while the share provided via the interconnection remained stable.

In supplemental reserves, one can see that this market has grown much more competitive over the past 15 months in terms of a much more balanced division of providers by fuel. It is encouraging to note the increased prominence of load in the supplemental reserves market to typically over 20% of this market since the beginning of 2005.

Figure 25 - Regulating Reserve Market Share by Fuel Type

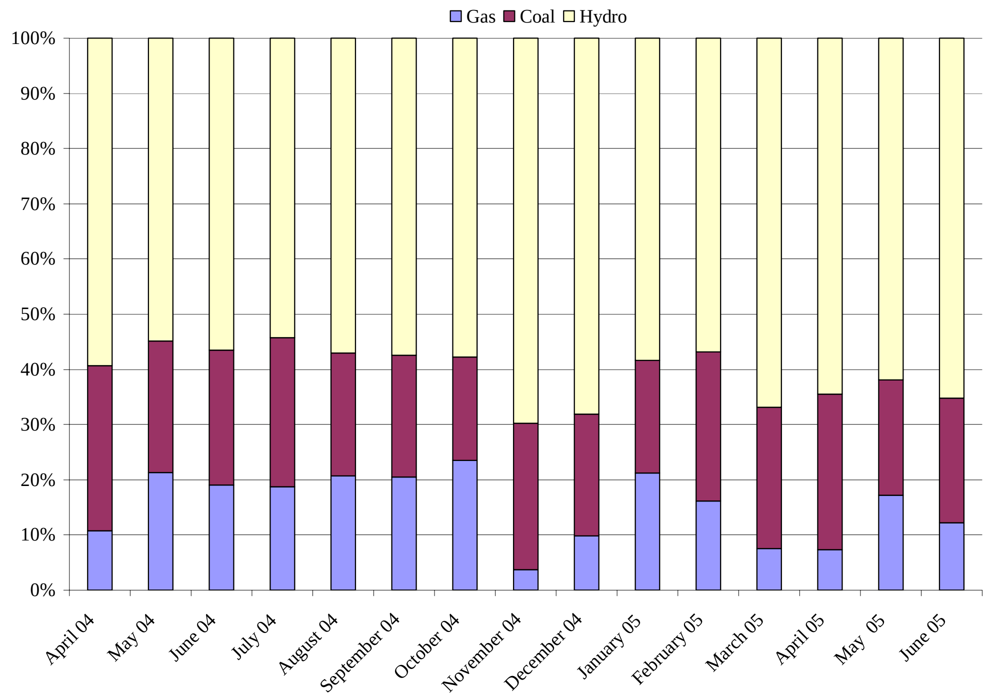


Figure 26 - Spinning Reserve Market Share by Fuel Type

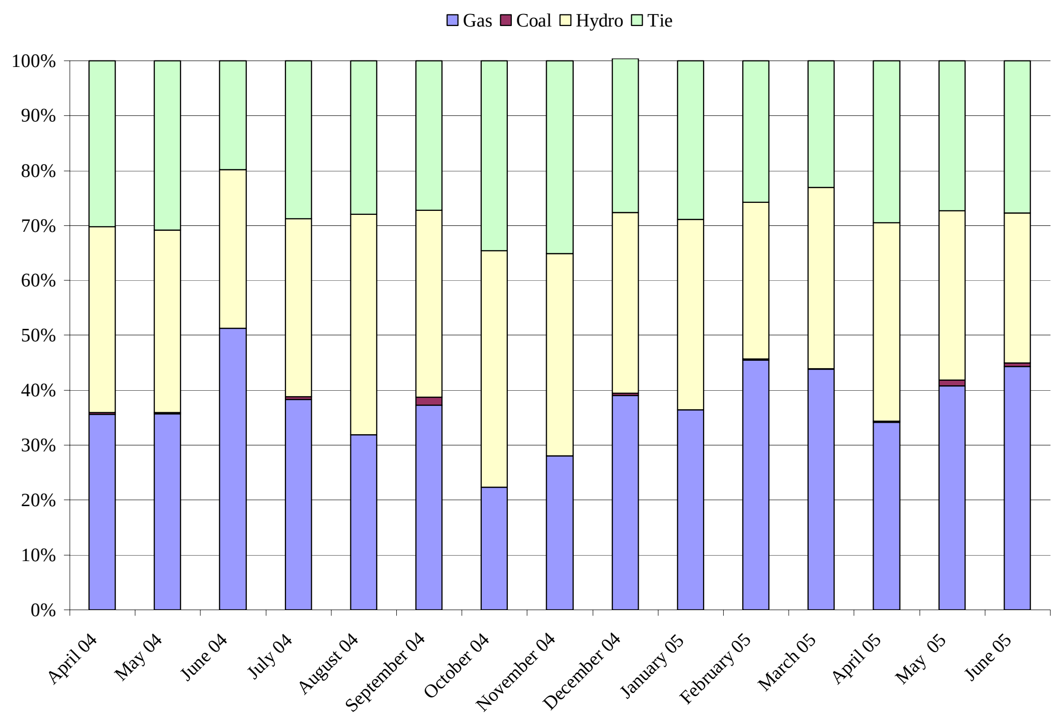
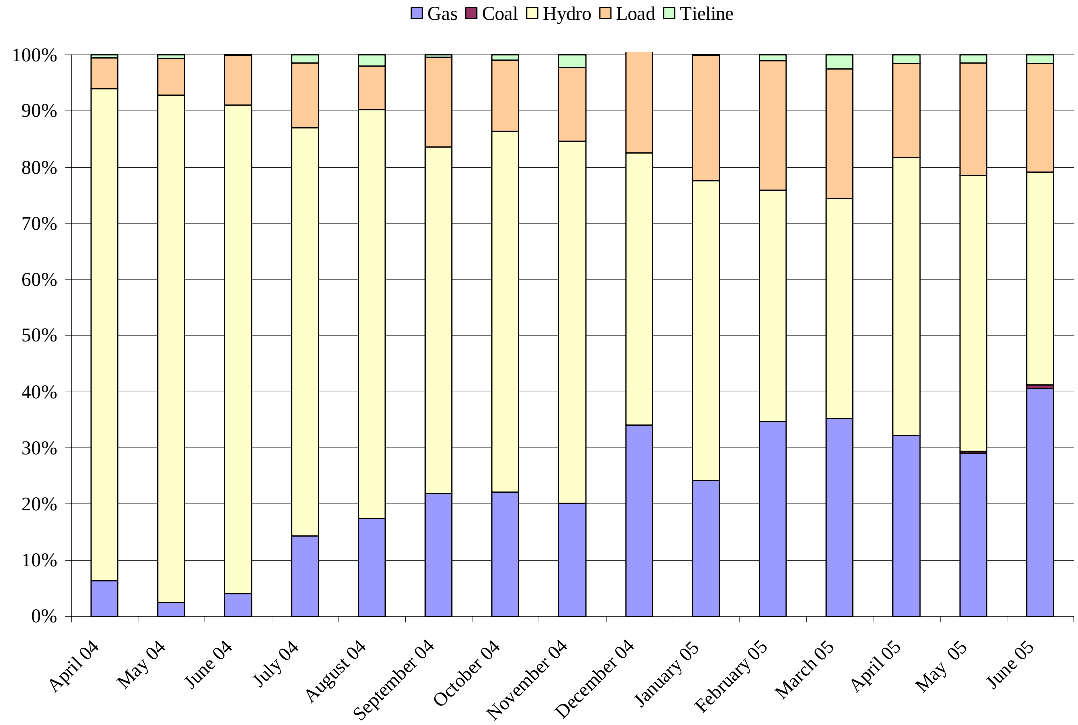


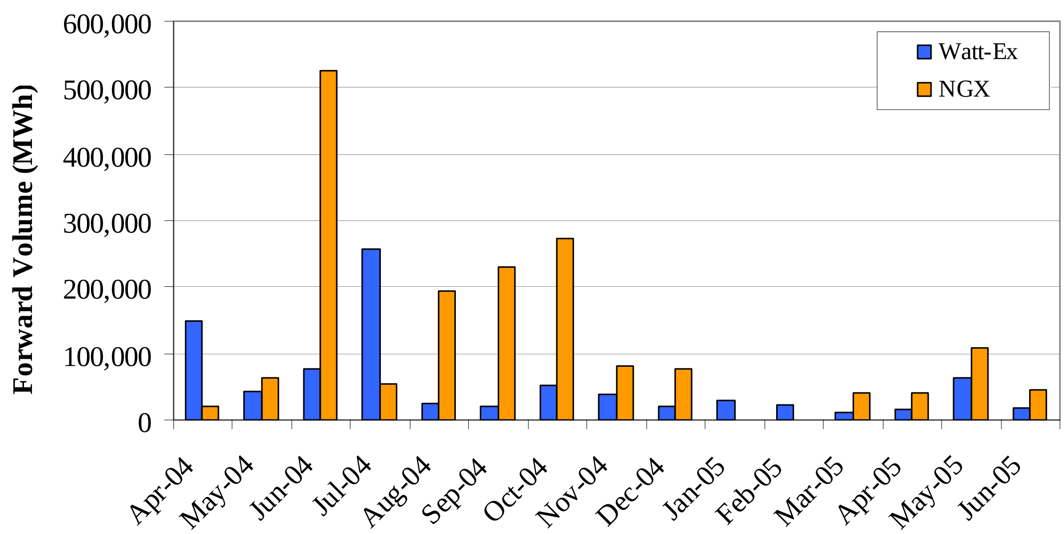
Figure 27 - Supplemental Reserve by Fuel Type



1.10 Forward Markets

Exchange traded forward energy volumes in Q2/05 were 293,625 MWh which was a significant improvement over the scant 104,310 MWh observed last quarter. **Figure 28** indicates that NGX and Watt-ex forward energy trading has been particularly thin since early Q4/04.

Figure 28 - Exchange Traded Forward Energy Volume



1.11 Outages and Derates

The MSA is interested in the frequency and duration of the outages and derates of generating units in Alberta. Of particular interest are the coal fired thermal generation units that are operated under the terms and conditions of the Power Purchase Arrangements (PPAs). Outages at these PPA plants tend to have a large impact on Pool price as they represent a major contingent of total installed generating capacity in Alberta.

In instances where these base load PPA units are derated or come offline due to an outage, a higher cost peaker unit is often dispatched to replace the base load energy that is no longer available for the provincial electricity needs. When the amount of outage exceeds a PPA unit's historical average, the MSA seeks to understand the cause of the variation and may request additional data from the generation owner.

Figure 29 illustrates the total outage levels at the coal fired generation facilities and is separated by PPA owner. This graph indicates the outage levels for the past five quarters and provides a context for the outage behavior in the most recent quarter. Owners A and B show elevated outage levels in Q2/05 which can be attributed to planned maintenance during the quarter.

It is typical to see planned outages scheduled for the second quarter of the year as this period is historically a shoulder load period between the higher demand winter and summer seasons. It should be noted that some variation is expected on a year over year basis due to the nature of multi-year planned outage schedules. With this in mind it would not be considered overly unusual for varied levels of outage to be experienced year over year. The MSA will continue to monitor outage of specific owners to ensure they are reasonable and within tolerances given the age and past performance of the generation units.

Figure 29 - Quarterly Outage Rates by Owner

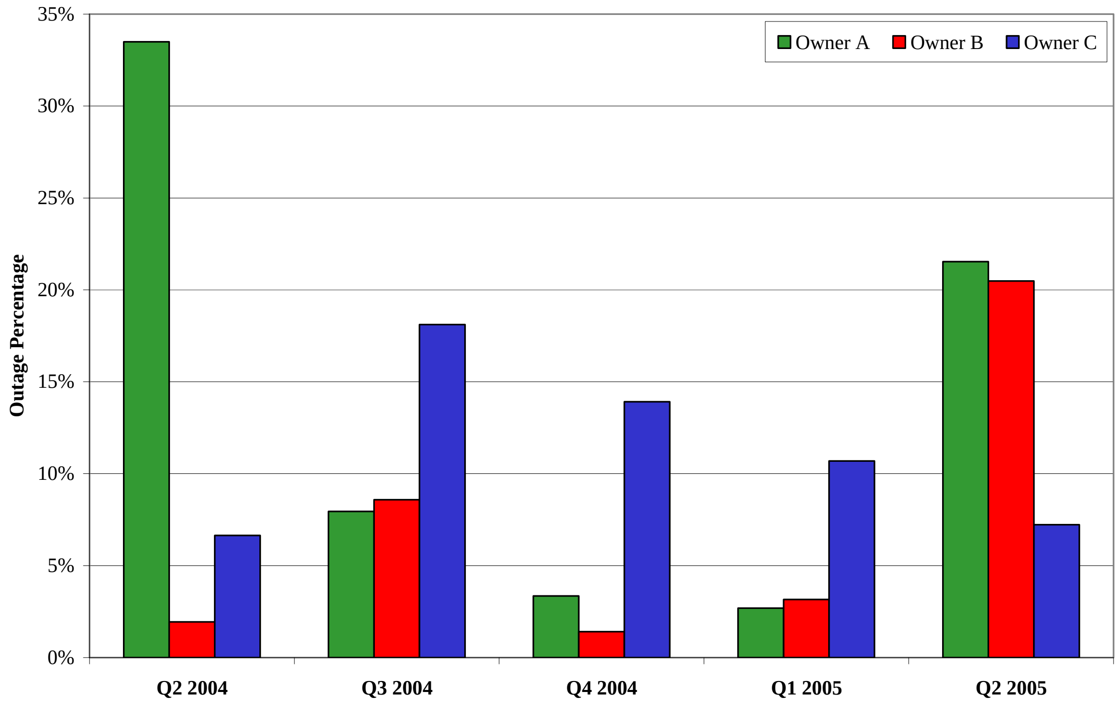


Table 4 reports the unplanned outages on a quarterly basis for the second quarter of 2005 and also provides a look at the previous annual statistics for unplanned outages as a point of reference. Q2/05 unplanned outages are elevated with respect to recent annual averages which is not so surprising given that more planned maintenance tends to be scheduled in the second quarter relative to the balance of the year.

Table 4 - Percentage of Unplanned Outages For PPA Coal Units

	Q2/05	**2004**	**2003**	**2002**	**2001**
Owner-A	**7.9%**	6.1%	4.9%	4.2%	3.2%
Owner-B	**3.6%**	1.5%	1.5%	0.5%	1.2%
Owner-C	**6.5%**	6.3%	5.7%	10.8%	8.8%
PPA weighted average	**6.4%**	5.5%	4.9%	7.7%	6.3%

Note:
1) PPA units include: Genesee 1 & 2, Battle River 3, 4, 5, Sheerness 1 & 2, Sundance units 1 through 6, Keephills 1&2.
2) Outages rates are based on maximum continuous rating (MCR), not gross unit capacity.

Each PPA document specifies the target availabilities for each of the PPA units and these targets are determined with information based on historical performance plus other factors such as the unit age and design. By owner,

Table 5 reports the MW weighted average target availability for each coal fired portfolio and the actual availability achieved during 2003 and 2004 along with the most recent quarter. In Q2/05, Owner A and B were well below their target availabilities while Owner C was above. This is the opposite of what was observed last quarter and is not of great concern to the MSA since target availability is an average annual number which allows actual availability to fluctuate from quarter to quarter, allowing for forced or planned maintenance. **Table 5** suggests that historically, the incentives imbedded in the PPA's have resulted in owners maintaining above target availabilities.

Table 5 - MW Weighted Portfolio Target Availability (%) vs Actual Availability (%)

	Target Availability 2003	Actual Availability 2003	Target Availability 2004	Actual Availability 2004	Target Availability 2005	Actual Availability Q2 2005
Owner-A	87%	92%	87%	88%	87%	78%
Owner-B	90%	94%	90%	97%	89%	80%
Owner-C	85%	88%	87%	89%	87%	93%
PPA weighted Average	87%	90%	87%	90%	87%	87%

2 REVIEW OF THE RETAIL MARKET

2.1 Code of Conduct

Compliance Plans

Compliance plans are required from owners of electric distribution systems and their affiliated retailers; the plans set out the systems, policies and mechanisms to be used to ensure compliance with the Code. Compliance plans must be approved by the MSA before they are effective, and before the affiliated retailer begins to provide retail electricity services.

The practice to date has been for each owner and each affiliated retailer to establish and adopt a distinct compliance plan. However, based upon discussions with various stakeholders, the MSA agreed in May, 2005 that a unified plan approach would also be acceptable – in other words, that a common plan could be developed, and adopted by all relevant parties (owner and affiliated retailer(s)) within an organization.

It appears that at least some of the owners and affiliated retailers will utilize the unified plan approach, upon the view that it will add efficiency to their compliance structures and make it simpler to train their personnel.

Owner and Retailer Structure

In accordance with the policy set out in the *Electric Utilities Act*, it is generally stipulated that the functions of owners of electric distribution systems and the functions of retailers must be done separately. This functional separation has meant that the owner functions are handled by a different legal entity than the retailer functions.

Based upon discussions involving Alberta Energy, the MSA, rural electrification associations (REAs) and other stakeholders, it was determined that there would be merit in allowing REAs to carry on retail functions within the existing REA (owner) entity, so long as the REA is retailing only to its members.

The main driving forces were potential efficiency gains and cost reductions for those parties, without material impediments to regulatory oversight or retail competition. In June, 2005 an amendment to the Roles, Relationships and Responsibilities Regulation came into force in relation to those matters.

Self Retail

In March, 2005 the MSA received a complaint from an REA member concerned about an approach being put forward by their REA as "self retail". As described, the approach involved the REA contracting with members for energy at non-regulated rates.

Part of the concern was that the REA seemed to be taking a "negative option" approach to contracting; in other words, that the members could find themselves on the so called "self retail" rate in the event that they did not advise the REA that they were choosing another option.

The MSA conducted a preliminary assessment into the matters, pursuant to the MSA Investigation Process and Assessment Guidelines. During the course of the preliminary assessment, the REA went to lengths to assure its members that it would not be using a negative option approach.

The MSA ultimately concluded that the matters did not warrant an investigation. At the same time, the MSA continued to take the view that the "self retail" approach contemplated by the REA would, in fact, be retailing; as such, there would be implications pursuant to the Code of Conduct Regulation and other enactments.

In June, 2005 the MSA met with the Board of Directors to discuss the findings of the preliminary assessment and toward assisting the REA in understanding the view of the MSA on the proposed "self retail" approach. The meeting was constructive, and further discussions are contemplated.

Code of Conduct Audits 2005

The Code of Conduct Regulation contemplates that the owners of electric distribution systems and their affiliated retailers will undergo a compliance audit on an annual basis, within the oversight of the MSA. The MSA also has the power to obtain information and conduct testing pursuant to its overall surveillance and investigation mandate under the Electric Utilities Act.

As previously indicated, the MSA has elected to test Code of Conduct Regulation compliance through one independent audit firm retained by the MSA (Grant Thornton LLP), utilizing one common testing plan. The period being tested is July 1, 2004 through June 30, 2005, inclusive, with an additional stub period for certain parties due to their operational status in May and June, 2004.

There will be a total of 13 parties subject to the testing, from the Direct Energy, ENMAX, EPCOR and Fortis organizations.

The main testing is contemplated to occur in August and September, 2005. The MSA has been carrying out planning discussions with Grant Thornton and the parties subject to the testing.

Access to Customer Information

As previously reported, the MSA has been working with representatives of Alberta Energy, the Alberta Energy & Utilities Board (EUB) and industry stakeholders around ways to make access to customer information as practical and fair as possible. The main initiative to date pertains to simplifying information access between the owners of electric distribution systems and retailers.

The discussions were put on hold to a degree in Q2/05, while the policy work of Alberta Energy was concluded. However, it is anticipated that the discussions will be actively carried forward in Q3/05.

2.2 Retail Market Metrics

The MSA continues to track performance in the retail market based on various metrics across four general customer groups

The four primary customer categories that are reviewed include: the Residential RRT eligible, the Farm RRT eligible, the small commercial RRT eligible and finally the non RRT eligible category which are those that historically consumer greater than 250 MWh annually.

As of June, 2005 there were 116 active retailers in the Alberta electricity market, 80 of which are self-retailers.

Figure 30 - Current Market Share of Retailers by Load Q2/05

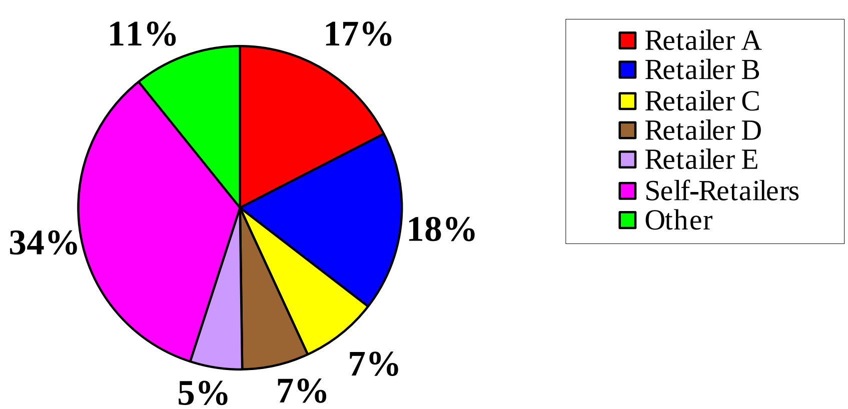


Figure 30 shows the overall provincial market share of retailers for Q2/05. The largest five retailers serviced over 54% of the total provincial load. Self-retailers, usually large industrial organizations, comprise another 34%, while assorted smaller retailers are competing for the remaining 11% of the market. The large amount of load in the self-retail category reflects the ability of larger industrial firms to manage their energy options in house as opposed to relying on default supply options provided by the incumbent retailers.

Figure 31 below, shows retailer market share by customer class for Q2/05.

Market shares of the three dominant retailers in the Residential – RRT Eligible class have not changed substantially over the last two years. Yet, a new retailer in this market will likely cause some changes in the market shares for the Residential category as competitive contracts become more common for everyday households.

In the Farm – RRT Eligible category, market shares have shown little change in the past quarter. This category is the smallest in terms of total load but with REAs becoming more involved in retailing, there may be a noticeable effect on market shares in the Farm - RRT eligible category.

For Q2/05, market shares of the main retailers in the Commercial/Industrial – RRT Eligible category have remained steady. The aggregate market share of the five largest retailers represents 77% of the total load. For some customers in this category, self-retailing may be appealing in order to have greater control over their energy costs.

Figure 31 - Q2/05 Market Share of Retailers by Customer Class

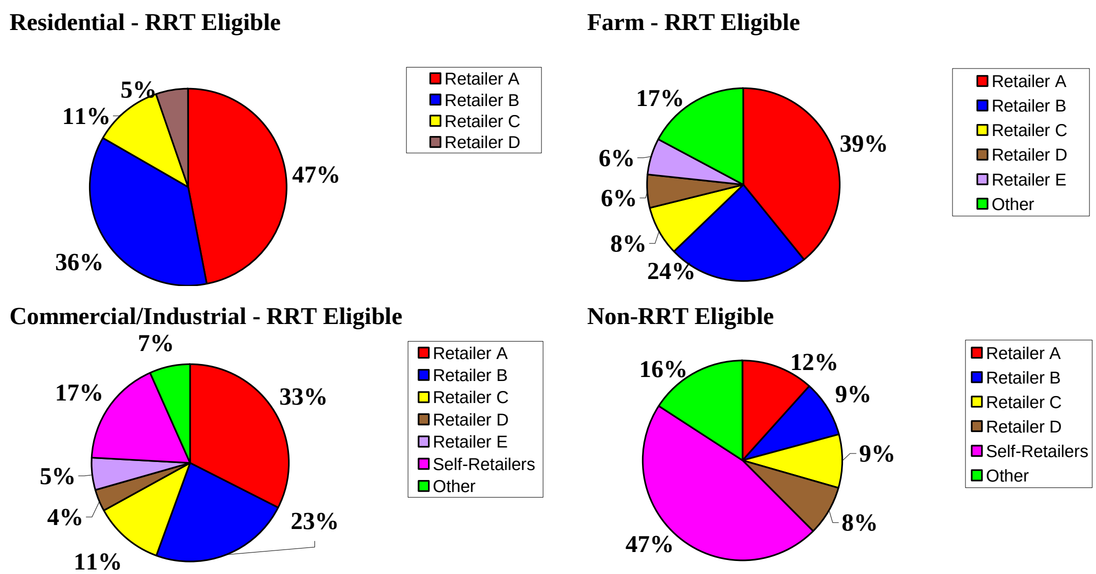


Figure 32 is another way to look at the shift in market share in the four categories. The picture is useful in providing an overall view of the change in market share over the past 11 quarters and demonstrates the changes experienced in the retail market. It is worthwhile to note the entry and exit of new retailers in the graphs which clearly shows the ongoing battle for market share in certain parts of our retail market.

Figure 32 - Change in Categories Q2/05

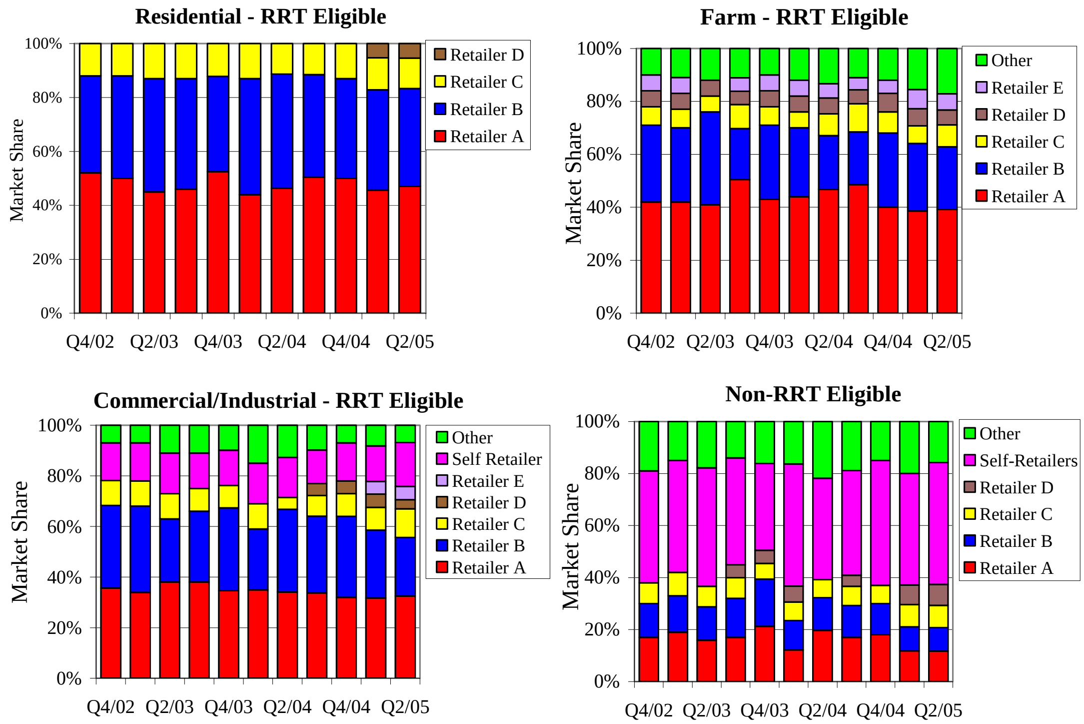


Figure 33 shows that the overall progression of customer sites switching off of the RRT to competitive electricity contracts leveled off in Q2/05 after trending upward over the two prior quarters. As of the end of Q2/05, 8.6% of all RRT eligible customer sites have chosen to enter into a competitive contract with a retailer.

Figure 33 - Progression of RRT Eligible Sites Switching Off RRT

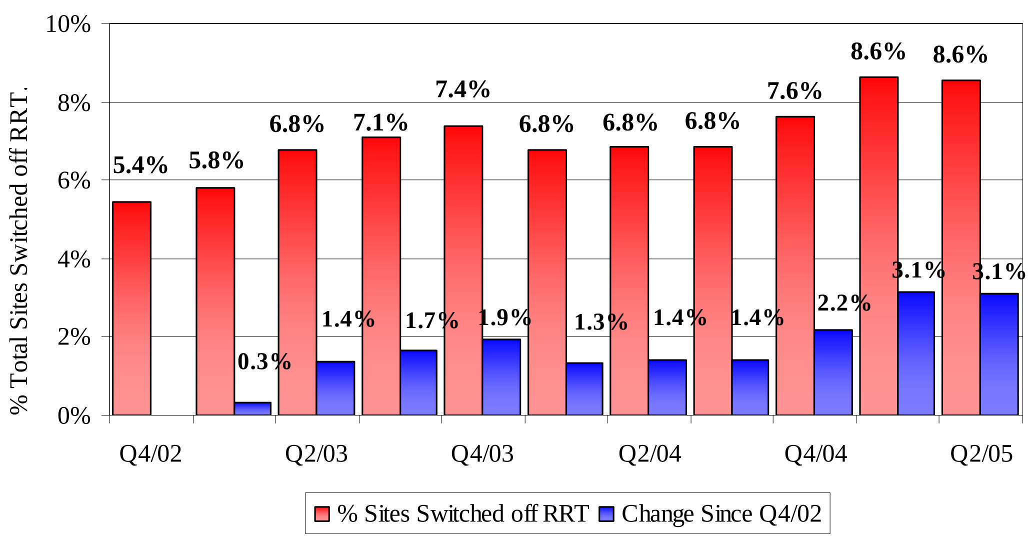


Figure 34 - Progression of RRT Eligible Sites Switching Off RRT by Customer Type

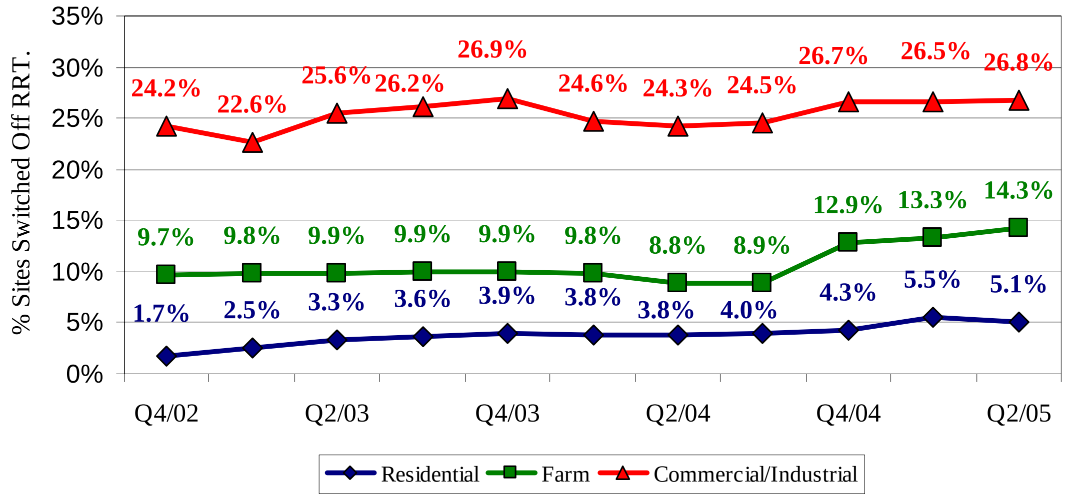


Figure 34 shows the progression of RRT eligible sites switching off RRT by customer type. Switching results are encouraging in all categories as no category has given up any real ground.

Switching rates in the Commercial/Industrial – RRT eligible category experienced a slight increase of 0.3% and reached the level of 26.8% and a bigger increase was seen in the Farm category up a full percent to 14.3%. The increase in switching indicates retailers are able to find customers in this category who find competitive contracts an attractive option to the regulated rate.

2.3 Settlement System Code Monitoring

The MSA maintains an interest in a wide variety of issues relating to Settlement System Code (SSC) and monitors how settlement is functioning in Alberta. As detailed monitoring of settlement and compliance to the SSC is the role of the AESO, the MSA's observations are more directional in nature - identifying trends in the settlement process.

Complaints

The SSC uses PFECs, PFAMs and Notices of Dispute as tools to resolve disputes resulting from the settlement process and calculations. PFECs occur prior to final settlement while PFAMs occur after or post-final settlement. Statistics regarding the number of PFEC/PFAMs submitted, accepted and rejected were collected from the four load settlement agents (LSAs) in the province. **Table 6** summarizes PFEC and PFAM tracking for Q2/05.

Table 6 - PFEC and PFAM Tracking

Claim Type	Carry-Over	Submitted	Accepted	Rejected	Unresolved	Net kWh Adjustment
PFEC						
Q2/05	67	317	187	6	191	NA
Q1/05.	224	56	202	11	67	NA
PFAM						
Q2/05	56	318	260	21	93	(12,246,637)
Q1/05.	20	141	26	102	33	(2,648,937)

The table shows that the number of PFECs submitted in Q2/05 have increased considerably from last quarter with a large number still left unresolved. The majority of the 191 unresolved PFECs source from one particular LSA. These processing statistics will continue to be closely monitored by the MSA to ensure the PFECs are dealt with expeditiously.

The overall volume of PFAMs submitted also increased substantially during Q2/05. The number of incoming PFAMs is an indicator that the LSAs are receiving challenges from retailers regarding the final settlement output. The significant quantity of accepted PFAMs suggests that many of the retailer issues are due to an error with the LSA settlement process. The MSA understands that the LSA has resolved these issues. The large negative value in the adjustment column indicates an aggregate overcharge to retailers which is being reversed.

Having 93 unresolved PFAMs is not an unusually high number but the MSA will keep a close watch to ensure these do get resolved in a timely manner and do not persist.

UFE

The MSA has collected data regarding UFE in the form of UFE Reasonable Exception Reports for each of the 10 settlement zones in the province. These public reports are posted on the LSAs websites and updated each time UFE in any given zone exceeds either general tolerances or tolerances set by the LSA. **Table 7** summarizes the UFE Reasonable Exception Reports (UFE reports) filed over the last two quarters.

Table 7 - Summary of UFE Reasonable Exception Reporting

Quarter	Outstanding	New	Resolved	Unresolved
Q2/05	19	18	5	32
Q1/05	12	21	14	19

By the conclusion of Q1/05 the number of UFE exception reports numbered 19 and many of these remained unresolved through the second quarter. This shows that some LSAs are not dealing with exceeded UFE tolerances in an acceptable manner[4].

Some LSAs are much better performers than others with one particular settlement zone being an overwhelming hindrance to the overall performance of the four main LSAs . The Ponoka and Fort Macleod areas have been unable to effectively manage their UFE tolerances in the past few months which raises a flag at the MSA and with the AESO settlement group.

Moderately positive results have come out of recent initial settlement figures but we would expect to see continuous progress in the resolution of these UFE issues in the very near future. If improvement is not evident, we would expect the AESO to take strong action to compel better performance in these settlement zones.

Non-Compliance, Enforcement Escalation and Enforcement Withdrawal Notices

In late 2003 the AESO initiated an enforcement ladder for the SSC[5]. The ladder identifies four levels of enforcement (increasing in order of severity from level 1 through level 4) depending on the seriousness of the non-compliance. If a party is assessed to be non-compliant at a certain level and the actions taken to correct the non-compliance are found to be unsatisfactory, the AESO may issue the party an Enforcement Escalation notice informing the party that their non-compliance has been elevated to the next level. Enforcement Withdrawal Notices are issued when the AESO finds that the party in question has satisfactorily dealt with the non-compliance issue or if the AESO finds that its initial assessment of the non-compliance issue was more severe than warranted.

Table 8 shows that two Level 1 Non-Compliance notices have been issued by the AESO in Q2/05. This indicates that overall compliance with the SSC is going well with only a few minor issues.

Table 8 - Non-Compliance Notices Issued (2005 YTD)

	Non-Compliance Notices Issued			
2005	**Level 1**	**Level 2**	**Level 3**	**Level 4**
Jan	0	0	0	0
Feb	0	0	0	0
March	0	0	0	0
April	0	0	0	0
May	0	0	0	0
June	2	0	0	0
YTD Total	**2**	**0**	**0**	**0**

[4] Most unresolved UFE reports are attributable to one individual settlement zone.
[5] See Section 4 of Appendix C of the SSC.

3 MARKET ISSUES

3.1 TPG / IDP Update

As noted in the MSA Q1/05 quarterly report, the MSA has been in the process of working with the AESO in the transitioning of generation outage reports that are published near real time based on the total declared energy values submitted via the Energy Trading System (ETS) by participants, per OPP 601. As of early July, outage reports became available via the AESO website reports section in the current category, under the titles of Short Term Outage and Monthly Outage. The MSA will continue to publish a load outage report as load outages are not reflected in total declared energy.

Also as noted previously, the MSA has undertaken a review of the TPG and IDP in terms of their impact on the market, in order to assess the effectiveness of this initiative against its intended benefits. This review will encompass a stakeholder survey to gather feedback, a review of forward energy trading activities, and additional metrics that attempt to measure the effect of TPG/IDP implementation.

3.2 Data Acquisition

The MSA's mandate requires it to oversee the trading practices of market participants. Pursuant to this, during Q2/05 the MSA issued a number of information requests as part of its ongoing enforcement of the Trading Practices Guideline. Most parties responded to the information requests in a clear and timely fashion. However, with one participant the MSA was required to make repeated inquiries and found the participant's response to be deficient, and in our view less than reliable. As a result, and in accordance with section 55 of the Electric Utilities Act, the MSA enlisted the assistance of our forensic auditors to attend the premises of the participant and supervise the extraction of the required information from the participant's systems.

The trading practices assessments completed by the MSA were insightful on a number of fronts. Through the assessments, the MSA gained a clear understanding of the challenges faced by participants in managing dynamic information flows along with trading and portfolio management activities. Most entities appear to be managing these challenges well. The MSA was pleased to find that overall, there were no significant trading infractions. The MSA did note some data concerns with two entities, and as such, will revisit the data for these entities over a different time frame.

4 OTHER MSA ACTIVITIES

4.1 MSA Stakeholder Survey

The second annual stakeholder survey was conducted during Q2/05 and a summary report published to the MSA website in mid-June. This survey is designed to measure the general level of satisfaction of market stakeholders in how effectively the MSA discharges its mandate to foster a fair, efficient, and openly competitive market. The survey is also intended to identify areas for improvement.

Results from this year's survey showed that ratings overall were not dissimilar to the quite positive ratings received in 2004. The degree of consistency between the results for 2004 and 2005 were encouraging given that the survey samples of the two overlapped by only about 50%. The summary report of the survey findings can be reviewed at: http://www.albertamsa.ca/2448.html .