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MSA REPORT

Quarterly Report

July - September, 2004

27 October, 2004

MARKET SURVEILLANCE ADMINISTRATOR

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Market Highlights

- The average price of electricity in the Alberta wholesale spot market in Q3/04 was $54.33 / MWh which was down from both last quarter ($60.07 / MWh) and the same quarter in 2003 ($62.59/MWh). Year to date, the average market price at the end of Q3/04 was $54.43 / MWh which compares to $65.75 / MWh for the same period last year.

- Implied market heat rate for Q3/04 was 9.2 GJ/MWh which was up slightly from last quarter (9.1 GJ / MWh) but down from Q3/03 (11.4 GJ / MWh).

- Peak system demand reached 8578 MW in Q3/04 which represents a 1% increase from the same quarter a year ago. Average system demand in Q3/04 was 7399 MW which is up 4% from 7095 MW in Q3/03.

- Net imports in Q3/04 decreased to 150,184 MWh from 273,761 MWh in the previous quarter. In the same quarter a year ago, Alberta was a net exporter of 23,600 MWh.

- The Balancing Pool and TransAlta reached a new agreement in Q3/04 covering the reserves obligation component of the hydro PPA – the result has been a more logical trading index for active supplemental reserves on Watt-Ex.

- The MSA began regular publication of outage reports in early July. These reports enable participants to comply with the Information Disclosure Procedure (IDP) in support of the MSA's Trading Practices Guideline.

1 REVIEW OF THE WHOLESALE ELECTRICITY MARKET

1.1 Electricity Prices

Wholesale electricity prices moved lower in Q3/04 as compared to both the prior quarter and the same period a year ago. **Table 1** shows that prices were lower in Q3/04 on both an on-peak basis and an off-peak basis. Prices were relatively consistent month to month through the quarter as the range in monthly average price was only $6.38 / MWh.

The price duration curves in **Figure 1** indicate that while prices in Q3/04 were lower than prices in the previous quarter the majority of the time, Q3/04 had a higher instance of prices above $100/MWh. This suggests that the merit order curve was generally more L – shaped in Q3/04 relative to Q2/04 which reflects a more binary offer practice where participants either offer energy into the market as a price taker ($0.00 / MWh) or at a high price, with a large step function in the merit order in between.

While price volatility was marginally higher in Q3/04 relative to the previous quarter, it was significantly lower than the same period a year ago and as **Figure 2** indicates, price volatility over the last 6 months has declined relative to the prior 6 month period.

Table 1 - Pool Price Statistics

	Average Price	On-Pk Price	Off-Pk Price	Std Dev[1]	Coeff. Variation[2]
Jul - 04	56.55	65.18	45.61	44.94	79%
Aug - 04	50.17	63.00	33.90	45.25	90%
Sep - 04	56.33	68.76	40.79	47.79	85%
Q3 - 04	**54.33**	**65.65**	**40.10**	**46.07**	**85%**
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%**
Jul - 03	87.91	106.25	64.64	98.72	112%
Aug - 03	55.67	66.34	42.12	38.90	70%
Sep - 03	43.63	53.26	31.58	43.93	101%
Q3 - 03	**62.59**	**75.29**	**46.12**	**69.05**	**110%**

1 - Standard Deviation of hourly pool prices for the period

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

Figure 1 - Quarterly Pool Price Duration Curves

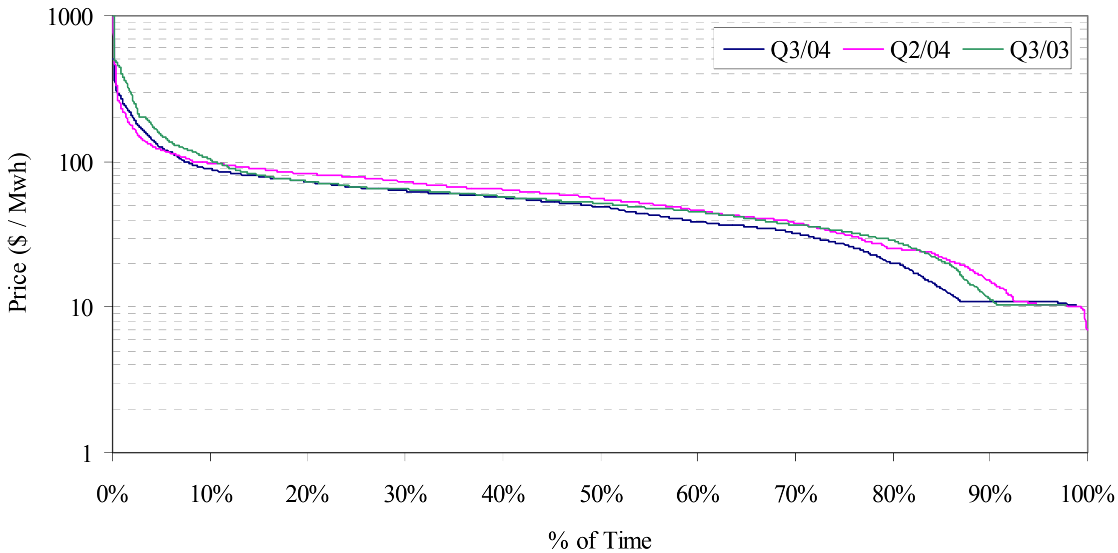
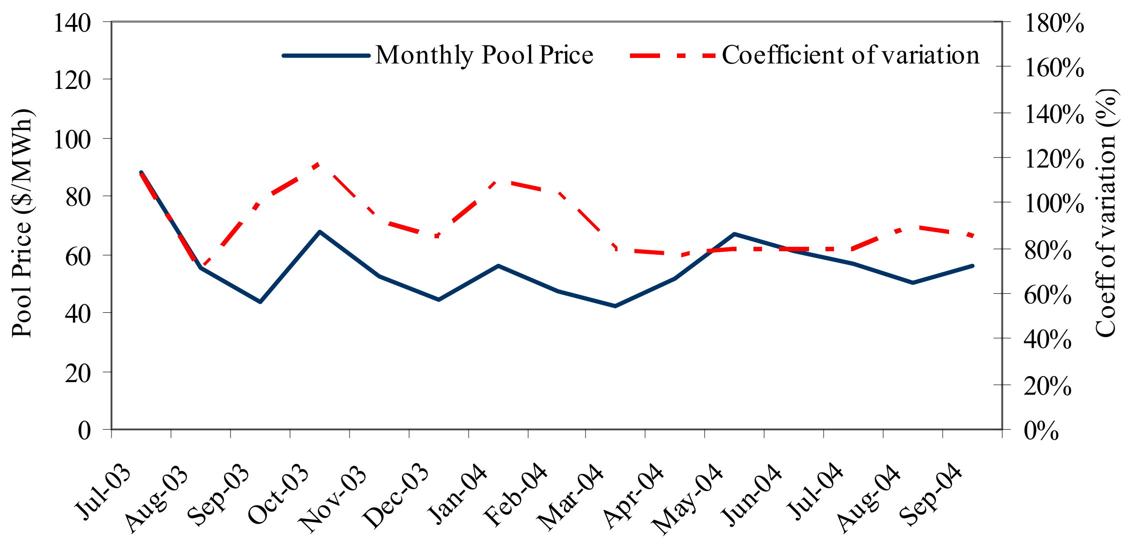


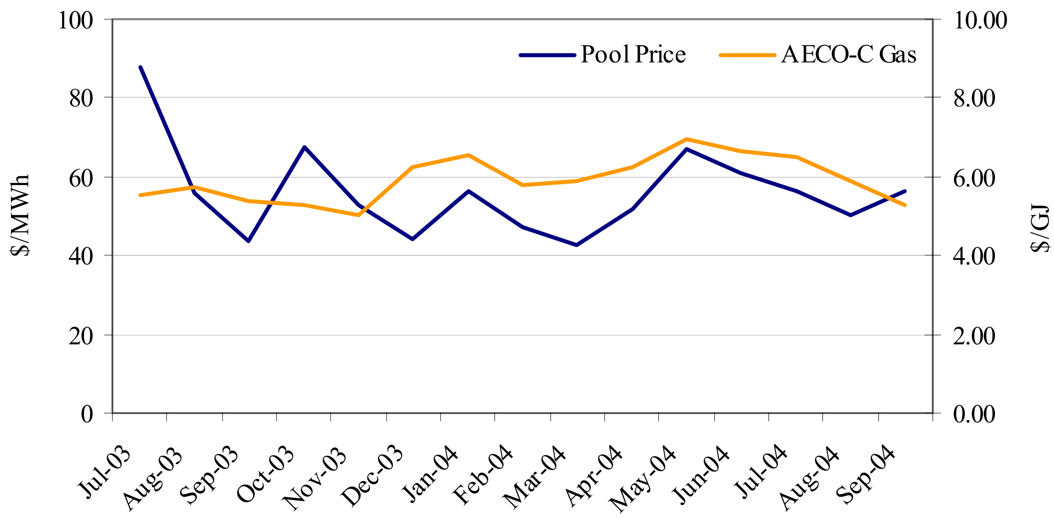
Figure 2 - Pool Price with Pool Price Volatility



1.2 Natural Gas Prices

Alberta gas prices continued to trend downward through Q3/04 after peaking in May at a monthly average price of $6.98 / GJ. **Figure 3** shows Alberta gas prices over the last 15 month period together with monthly average Pool prices. The trailing 12 month correlation of monthly average wholesale electricity price to gas price strengthened marginally to 0.19 at the end of Q3/04 from 0.17 at the end of the previous quarter but was down substantially from 0.50 as of the end of Q3/03. Correlation results over the last 12 months indicates that gas prices have been a weak predictor of electricity prices. At the end of Q3/04, working gas in storage stood near the top of the 5-year historical range – even so, forward gas prices are looking robust, with Alberta gas for the winter heating period trading recently in the mid $8.00/GJ range.

Figure 3 - Wholesale Electricity Price with AECO Gas Price



1.3 Price Setters

The distribution of marginal price setters for Q3/04 and the prior quarter is shown in **Figure 4**. The most frequent price setter set SMP a total of 29% of the time during Q3/04 while the most frequent price setter in the previous quarter set SMP a total of 21% of the time. Although the most frequent price setter set SMP a higher proportion of the time in Q3/04, this was on average, at a significantly lower weighted average price. This suggests that the market was well contested and the setting of elevated prices for disproportionate periods was not observed. In Q3/04 the 5 most active price setters collectively set price 74% of the time which was up from 69% of the time in the previous quarter.

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

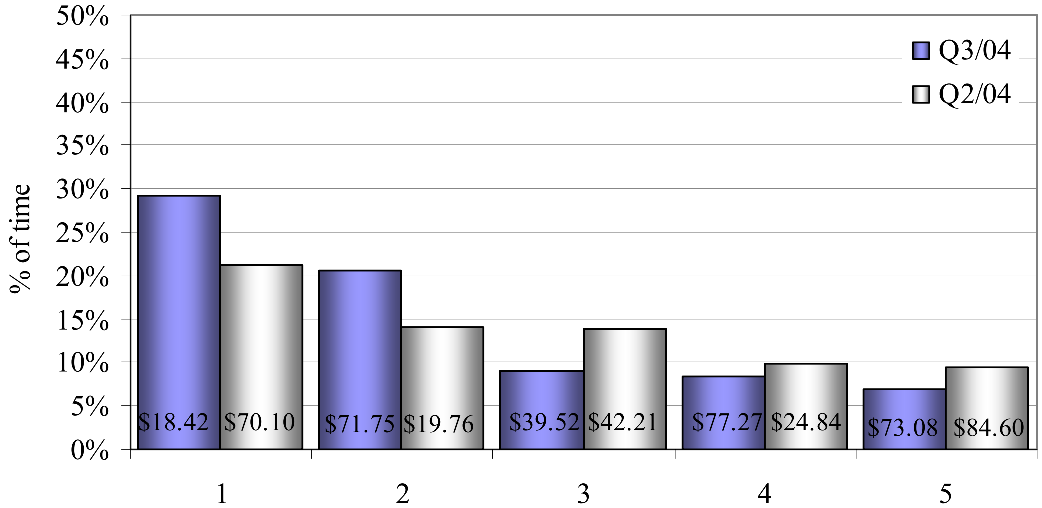
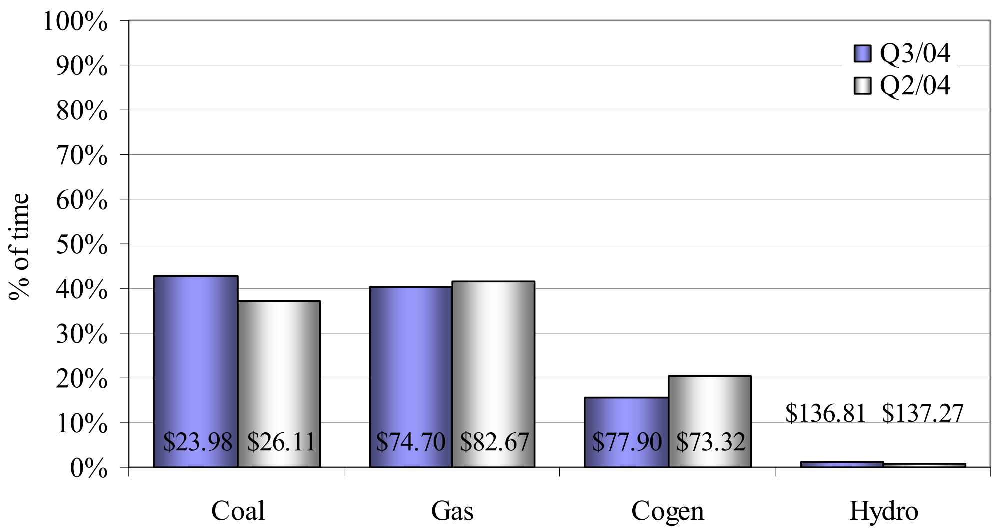


Figure 5 shows similar data on the basis of fuel type of the marginal unit. Coal units were more predominant price setters in Q3/04 than in the prior quarter but at similar levels of SMP. Gas units collectively (cogen + other gas) set price 56% of the time in Q3/04 at a weighted average SMP of $75.60 / MWh which was down from 62% of the time in the previous quarter and a weighted average price of $79.59.

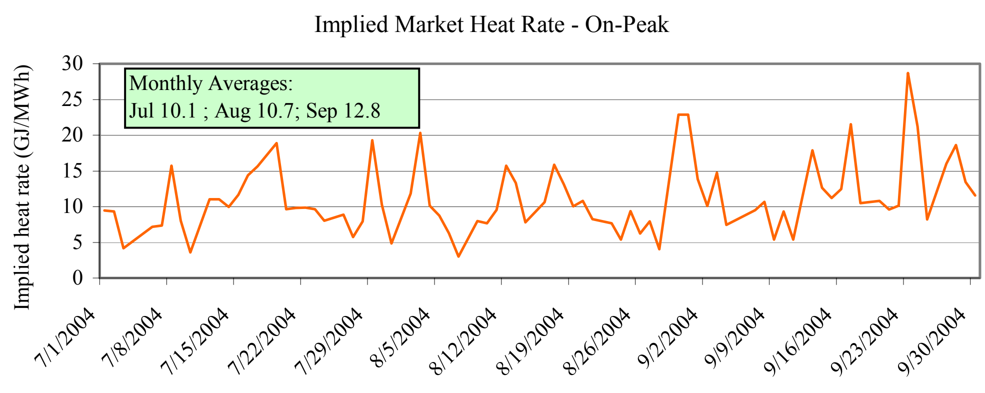
Figure 5 - Price Setters by Fuel Type (All Hours)

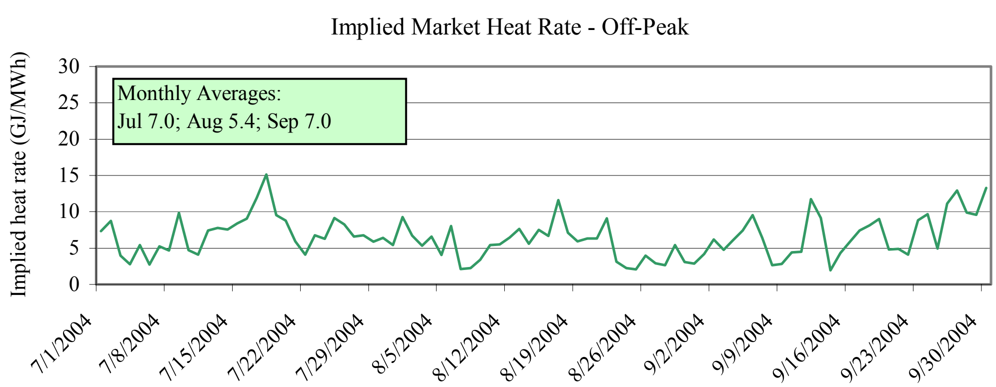


1.4 Implied Market Heat Rate

The average implied market heat rate moved up slightly in Q3/04 relative to the last quarter but was down from the same period a year ago. The difference year over year, primarily relates to strong on-peak prices in July 2003 which skewed the average Q3/02 number upward. **Figure 6** shows the on and off peak implied market heat rate through Q3/04. Although average monthly heat rates rose through Q3/04, downward trending gas prices contributed to flat monthly average Pool prices.

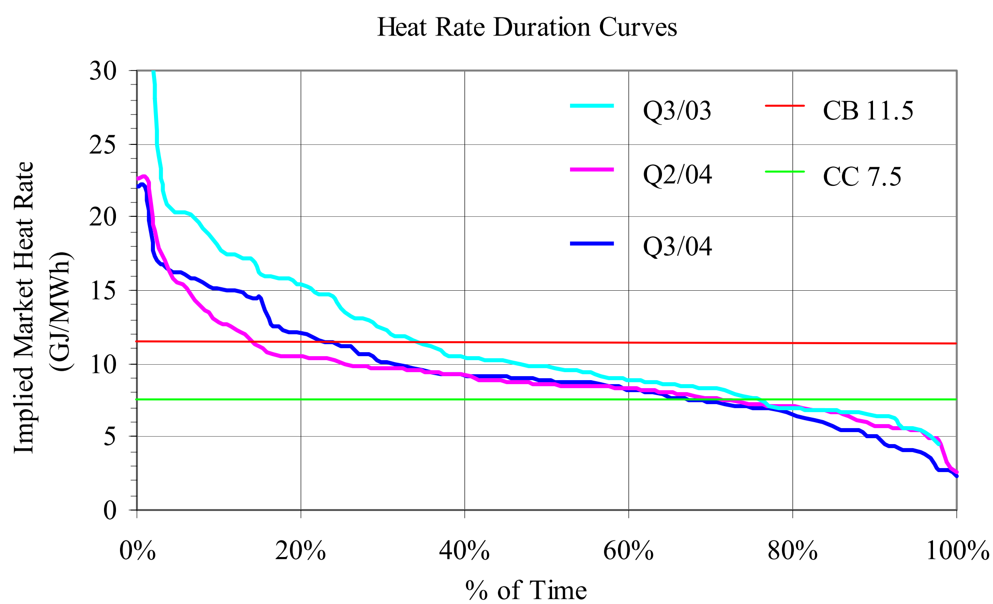
Figure 6 - Implied Market Heat Rates - Q3/04





The duration curves in **Figure 7** compare the distribution of implied heat rates on a quarter over quarter and year over year basis. A newer combined cycle gas generator would have been able to recover its cost of gas about 70% of the time in Q3/04; which is down marginally from approximately 75% of the time in the previous quarter. In the same period a year ago, the same generator would have been slightly more profitable, being in a position of recovering fuel costs about 77% of the time. **Figure 7** also underscores the economic viability of recently installed gas generators as compared to the last gas generators brought on-line in the previously regulated environment which would have been profitable only about 22% of the time in Q3/04.

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



1.5 New AESO Rules

There were no significant changes to AESO rules during Q3/04.

1.6 New Supply and Load Growth

30 MW of new generation capacity was brought on line in late Q3/04 from the Magrath Wind Power Project.

The monthly average hourly system demand for electrical energy in Q3/04 was:

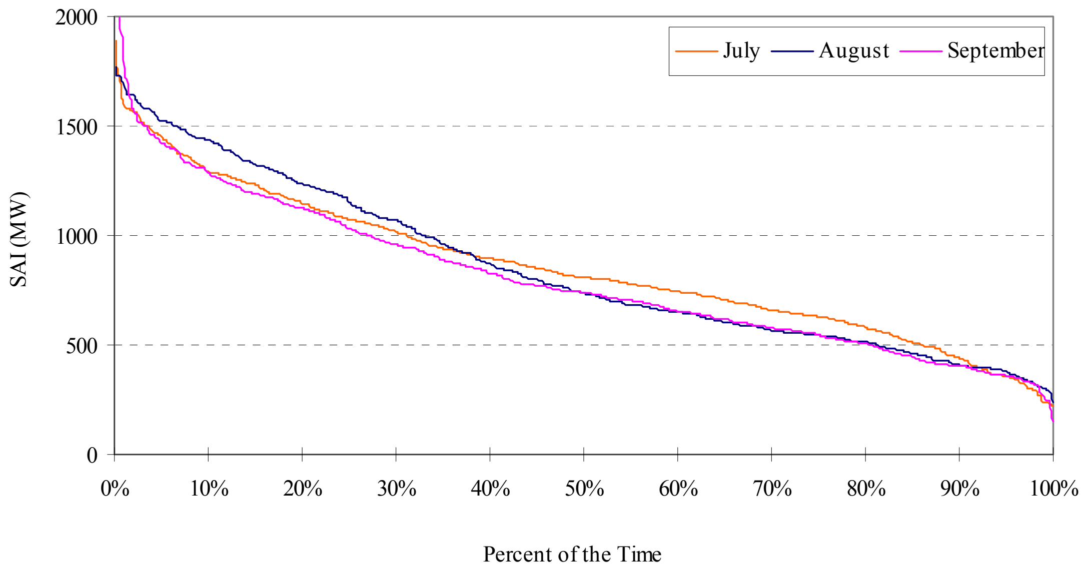
July	7455MW	+5.1 % vs. Jul 2003
August	7399 MW	+3.2 % vs. Aug 2003
September	7340 MW	+4.6 % vs. Sep 2003

In Q3/04, peak demand was 8578 MW which was reached in HE 17 on July 19. The wholesale price in the same hour was $95.03. Peak demand increased 1.0 % from peak demand recorded in the same period a year ago. For Q3/04, the system load factor was 86% which compares to 84% last quarter and 86% in Q3/03.

1.7 Supply Availability Index

Supply availability index is a proxy for residual supply in the market and is defined here as the average quantity of energy offered into the merit order above the level of dispatch in each hour of the period in question. **Figure 8** shows duration curves for each month of Q3/04 which suggests that overall, the month of July had greater residual supply than August and September. The figure also shows that the quarter was relatively consistent at the right end (tight end) of the curves where price response is most pronounced. This feature is reflected in the consistency of market prices through the quarter. In Q3/04, the correlation between SAI and Pool price declined markedly to -0.28 from -0.54 in the previous quarter and -0.44 in Q3/03. A lower correlation here suggests a more pronounced L-shape in the offer curve in Q3/04 as compared to both the previous quarter and the same quarter a year ago.

Figure 8 - SAI Monthly Duration Curves, Q3/04



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 2** summarizes the activity on the tie-lines for Q3/04.

Table 2 - Tie Line Activity Q3/04

	BC			Saskatchewan			Overall		
	Imports	Exports	Net Imports	Imports	Exports	Net Imports	Imports	Exports	Net Imports
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
July	*132,398*	*98,363*	*34,035*	*54,710*	*1,415*	*53,295*	*187,108*	*99,778*	*87,330*
August	*64,776*	*118,828*	*(54,052)*	*83,866*	*2,140*	*81,726*	*148,642*	*120,968*	*27,674*
September	*64,848*	*72,274*	*(7,426)*	*43,306*	*700*	*42,606*	*108,154*	*72,974*	*35,180*
Total	**262,022**	**289,465**	**(27,443)**	**181,882**	**4,255**	**177,627**	**443,904**	**293,720**	**150,184**
On-Peak	87%	21%		63%	68%		77%	22%	
Off-Peak	13%	79%		37%	32%		23%	78%	

Alberta was an overall net importer for the quarter with 150,184 MWhs. Import volumes were substantial on both the BC and SK tie lines during the on peak period. Export activity was considerable on the BC tie, and for the most part was during the off-peak hours. Conversely, there was very little exporting on the SK side with only 4,255 MWhs. The Saskatchewan tie-line was primarily used for imports, with import volumes on the SK tie actually exceeding those on the BC side in August. High import levels in July and August were likely due to generation outages that required some participants to rely on imported energy to cover their short physical position. Over the course of the quarter, Alberta imported about 440,000 MWh and exported close to 300,000 MWh of electricity.

Figure 9 shows the relative market shares of importers and exporters in Q3/04. 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 38% market share of imports (constant from last quarter) and a 78% market share of exports (up slightly from 72% last quarter). The second largest importer has increased its market share by 13% (up to 37% from 24% last quarter) while the third largest importer dropped by 5% from last quarter to a level of 11%. The market shares for participants remained generally constant on the export side with the only notable change being that some market share was lost by the second largest exporter to the largest player.

Figure 9 - Market Share of Importers and Exporters, Q3/04

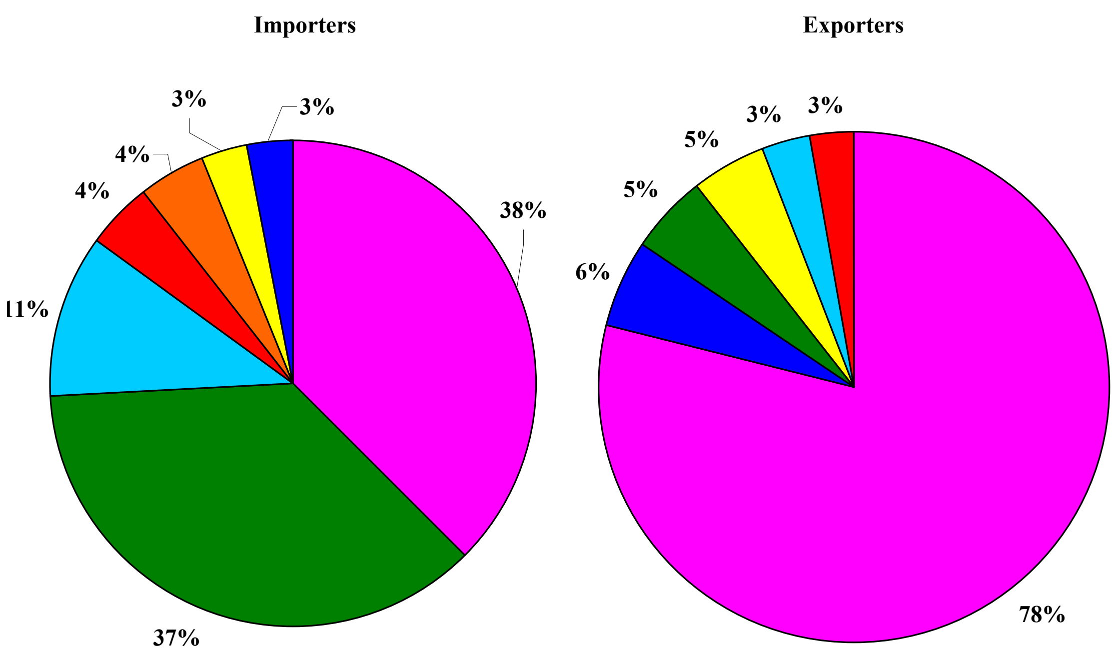
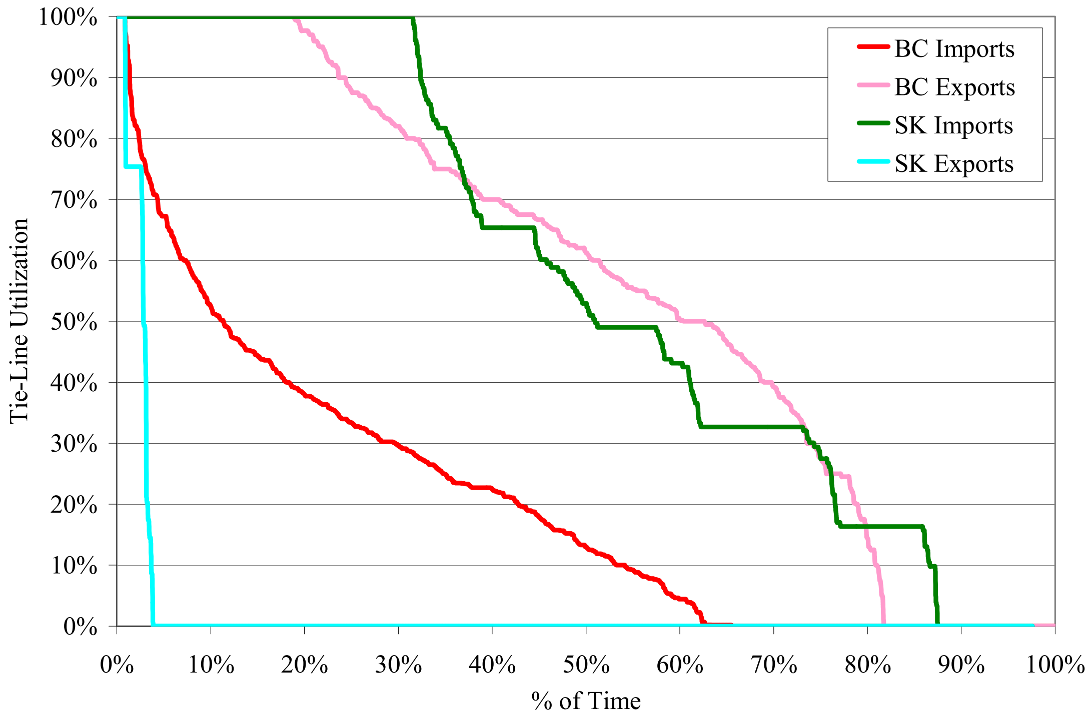


Figure 10 shows duration curves for tie-line utilization in Q3/04 as a function of posted available transfer capability (ATC)[1]. The figure shows that there is often some unutilized capacity available on both of the tie-lines. The SK import ATC was the most effectively utilized in Q3/04 as there was some volume of energy being imported to Alberta from (or through) SK approximately 87% of the time that the line was available. The BC export ATC was only slightly less used coming in at 81% utilization. The Saskatchewan export capacity was by far the most underutilized during the quarter.

[1] 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.

Figure 10 – Tie-Line Utilization, Q3/04



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 average monthly on-peak pool prices and total monthly exports with average monthly off-peak pool prices respectively for the July 2003 through September 2004 period. During Q3/04, 77% of imports occurred during on-peak hours and 78% of exports occurred during off-peak hours, therefore comparisons with on and off-peak prices are appropriate.

Figure 11 – Imports and On-Peak Pool Price

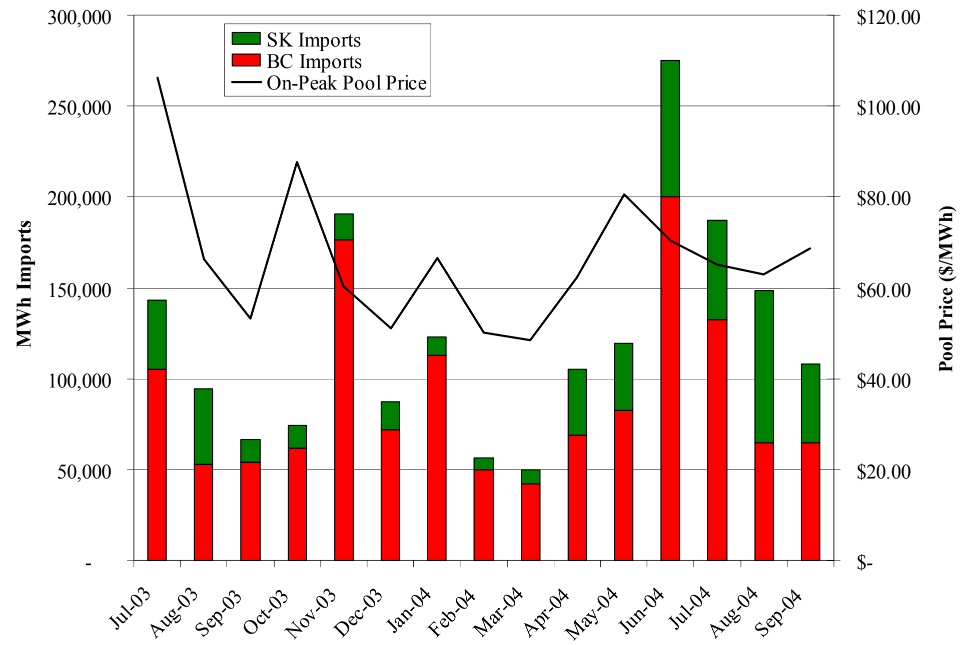
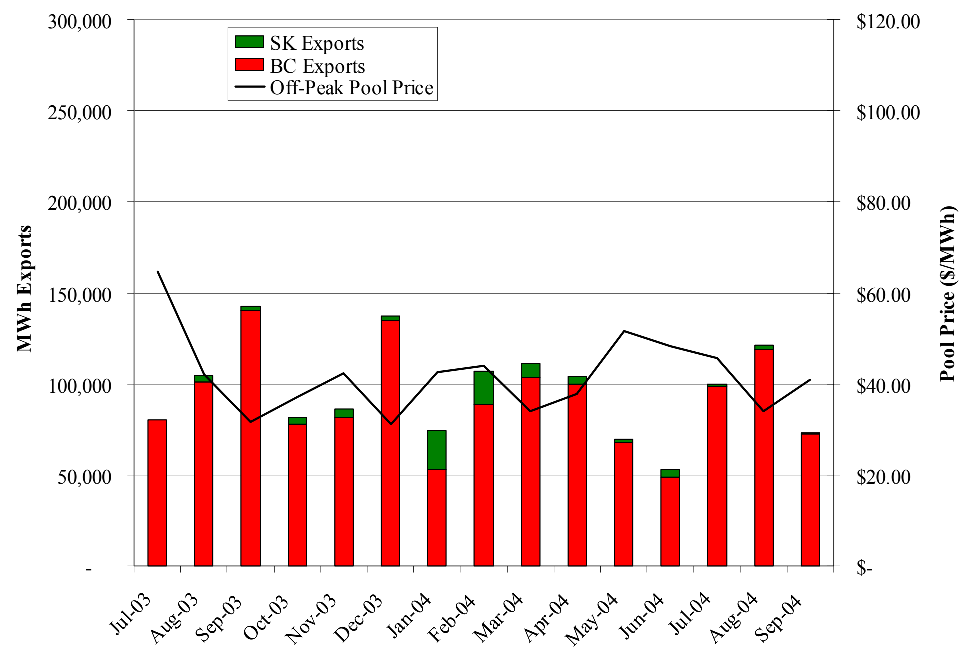


Figure 12 – Exports and Off-Peak Pool Price



Over the quarter, import volumes corresponded fairly well with on-peak Pool prices – as prices increased, the volume of imports increased.

The expected inverse relationship between off-peak Pool price and export volumes was apparent during the quarter and especially visible in August and September. Imports from (and through) Saskatchewan have increased dramatically over the last six months. In Q2/04 imports on the

Saskatchewan tie-line totaled 148,286 MWh and Q3 imports were even higher with 181,882 MWh being brought in.

Figure 13 - Price Paid for Imports and Exports

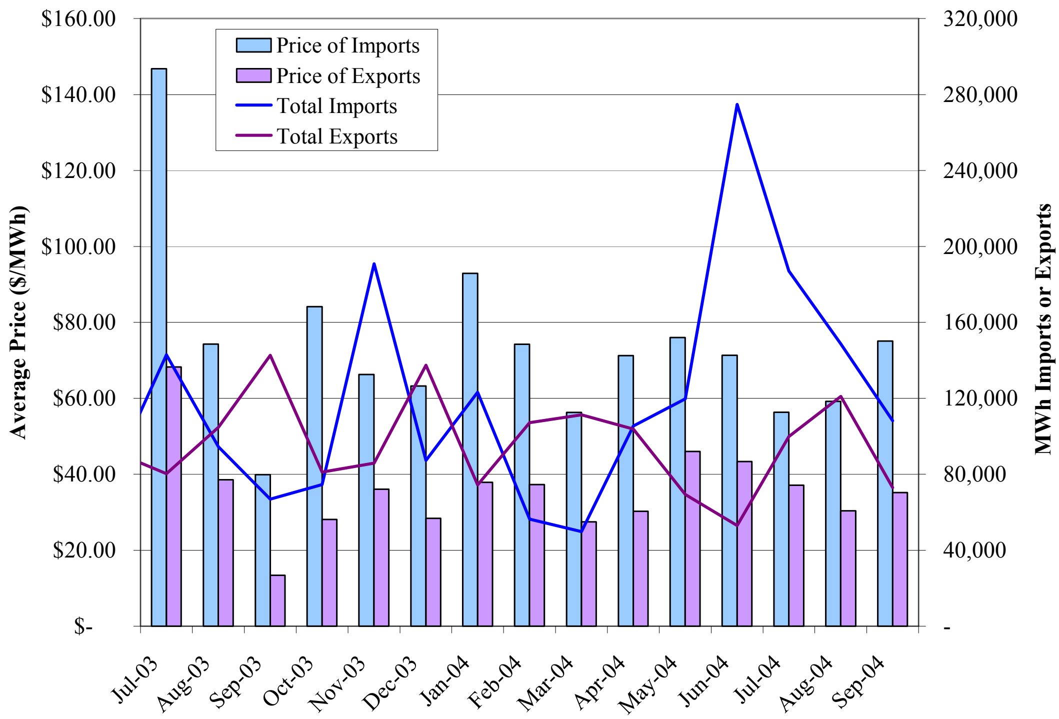


Figure 13 plots the volume-weighted monthly average price paid to importers and paid by exporters along with total monthly imports and exports for the past 15 months. For the quarter, the average price paid to importers was $63.54/MWh while the average price paid by exporters was $34.22/MWh. (These values exclude the cost of transmission and losses.)

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 14 and 15** show monthly average on-peak and off-peak price indices for MAPP-North (US Mid-West) and Mid-C (US Pacific Northwest) compared to Pool price. All prices are in Canadian dollars and have been converted at the daily exchange rate.

Figure 14 - On-Peak Prices in Other Markets

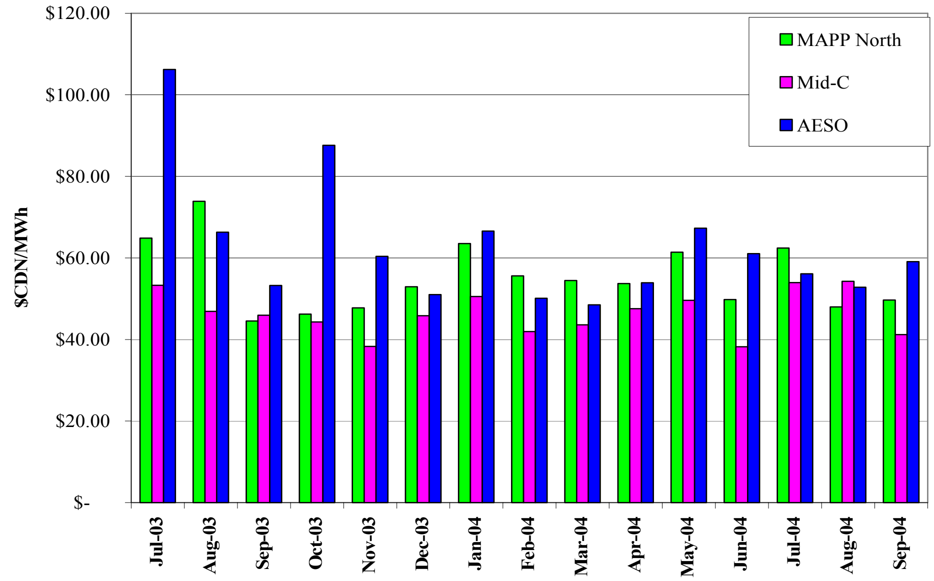
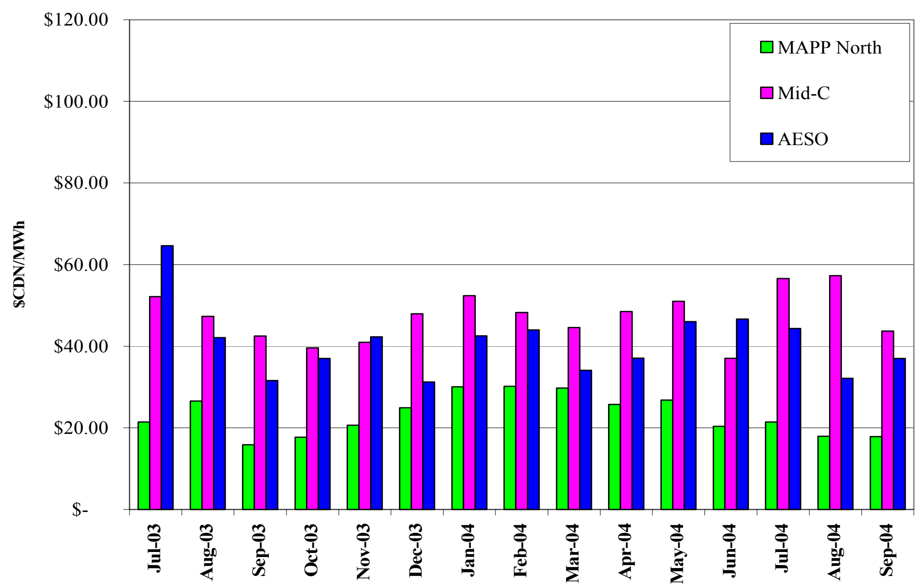


Figure 15 - Off-Peak Prices in Other Markets



On-peak Prices at MAPP-N were similar to Pool prices during the quarter which would make it difficult to consistently economically import from MAPP to Alberta. On-peak prices at Mid-C were also similar to Pool prices but dropped lower in September, although import volumes (**Table 2**) did not seem to respond.

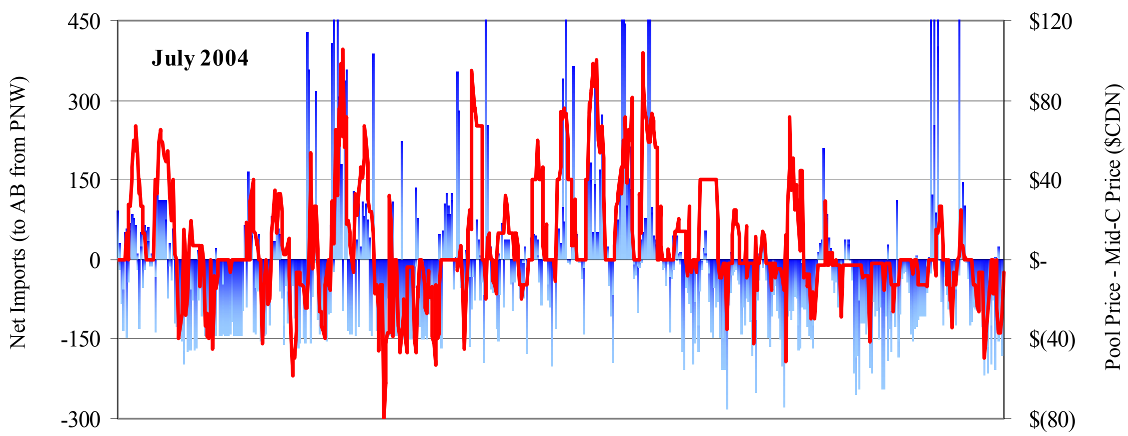
Alberta prices were generally between the higher Mid-C prices and lower MAPP-N prices. These price differentials tend to support off-peak exporting to Mid-C and off-peak importing from MAPP-N. This is reflected in the actual import/export activity observed over the last quarter, except exports are primarily to BC rather than Mid-C.

Because neither BC nor Saskatchewan operate open markets, it is difficult to assess the economics of moving energy to and from these areas. However, energy is often moved through BC and Saskatchewan to markets in the US[2]. **Figures 16 and 17** attempt to capture the economic use of the BC and Saskatchewan tie-lines over the last quarter. In the graphs, hourly net imports from beyond BC and Saskatchewan are plotted with daily on and off-peak price differentials. Lines and bars on the same side of the x-axis indicate economically efficient tie-line usage. Calculations do not take into account the cost of transmission from one jurisdiction to another. Energy that originated in or was delivered to BC or Saskatchewan is not included in the analysis.

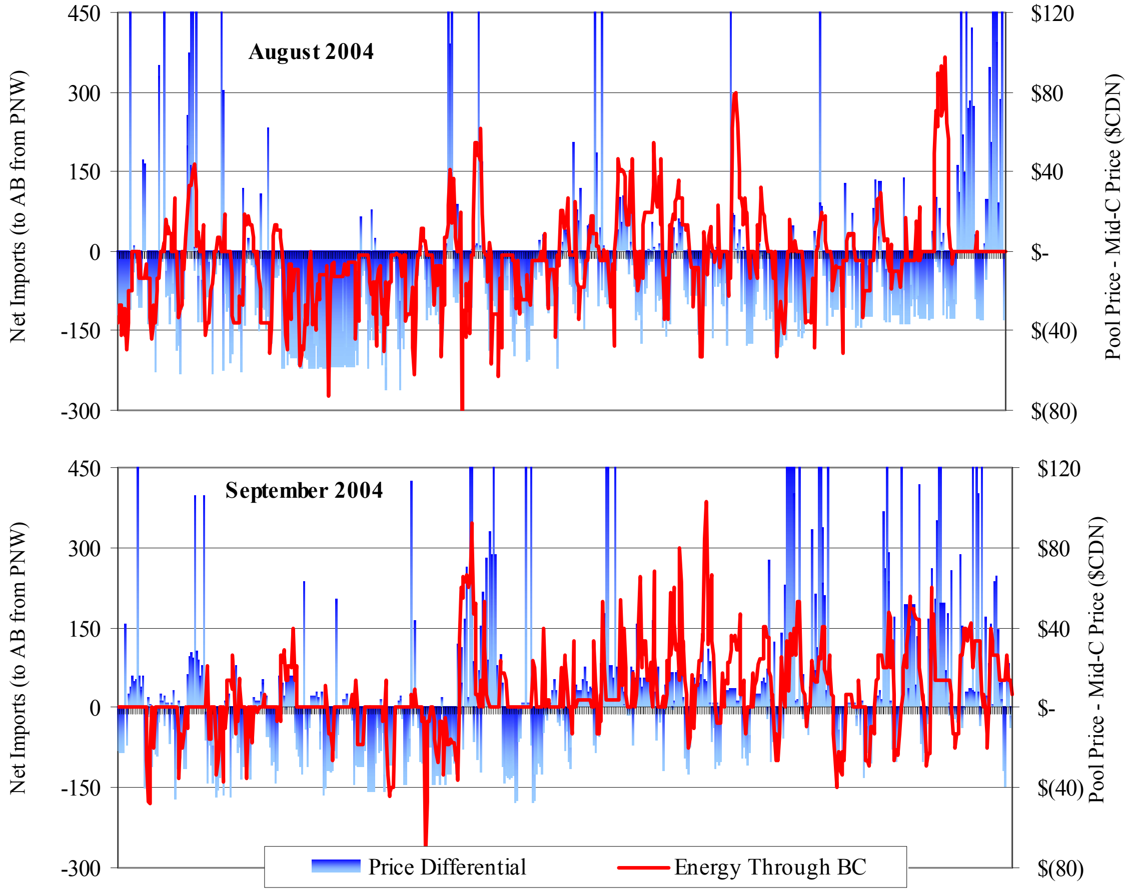
Figure 16 indicates that for the majority of the quarter, energy moving through BC was traveling in the implied economic direction and in general, high price differentials were captured in both directions. The only times where imports and/or exports appeared to be moving in the wrong economic direction were when the price differentials between the two markets were fairly modest and would not likely cover the cost of transmission and losses between the source and sink of the power.

The MSA is currently conducting an analysis on the tie lines (see Section 3.2) and based on this work, may revise it's approach in covering the tie-lines in future quarterly reports.

Figure 16 - Economic Use of the BC Tie Line

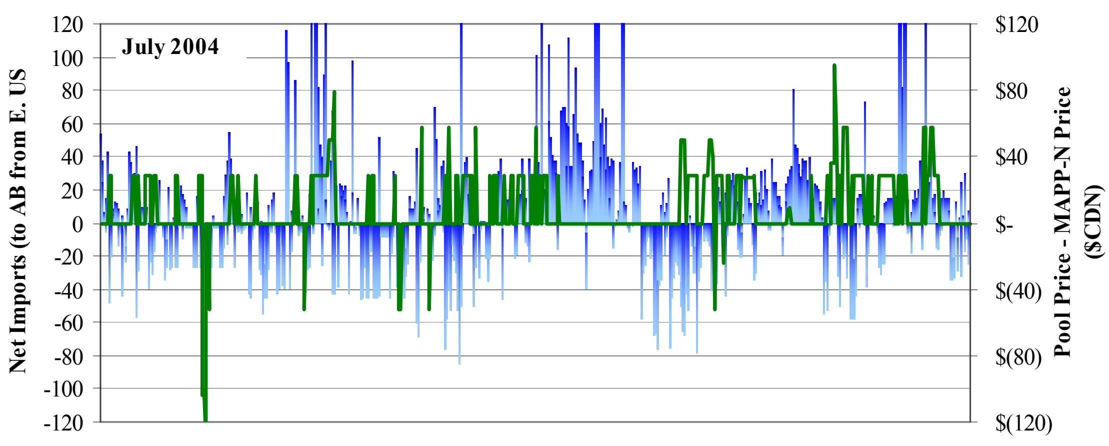


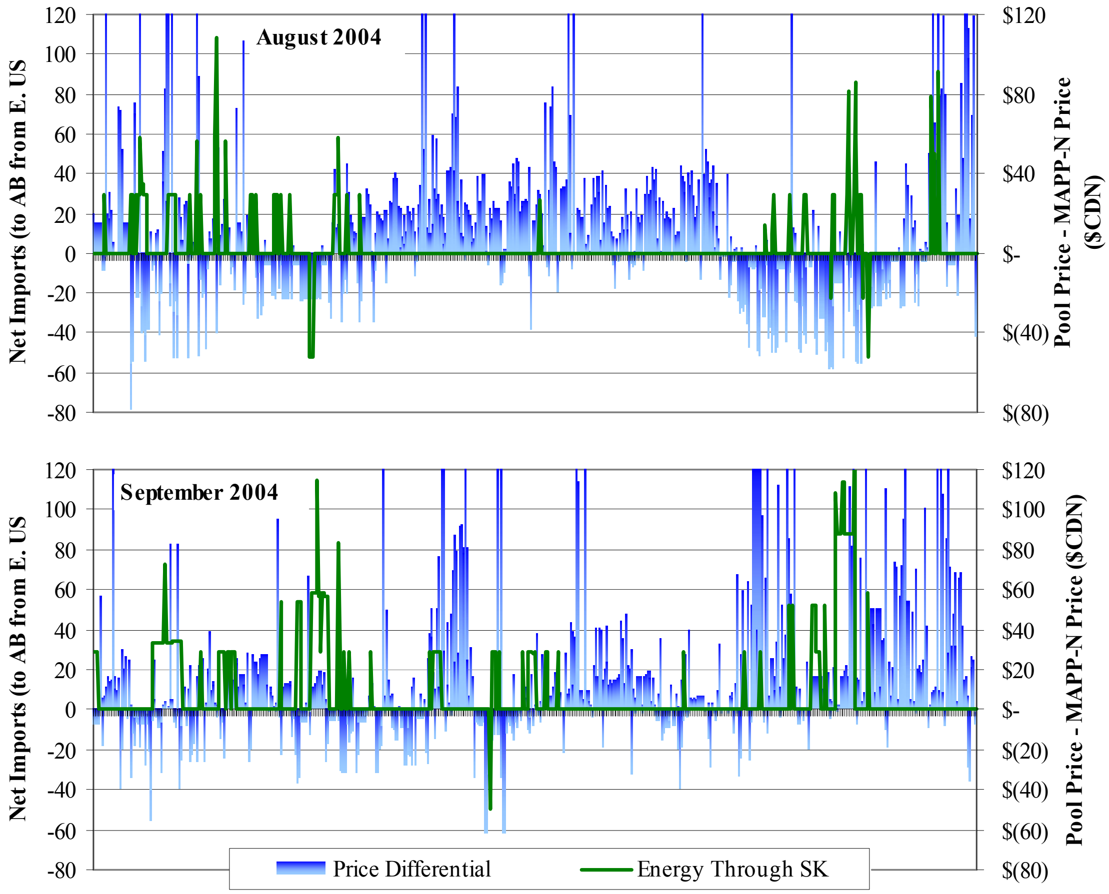
[2] The difference in the price at which energy can be bought and sold gives an indication of the economically correct direction for energy to be moving across the tie-line. For example, if the Pool price in Alberta is $50/MWh and the price at MID-C is $100/MWh, it would be most economically efficient 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.



Note: logical economic direction is indicated when the blue and red lines move in the same direction.

Figure 17 - Economic Use of the Saskatchewan Tie Line





Note: logical economic direction is indicated when the blue and green lines move in the same direction.

1.9 Ancillary Services Market

Active Reserves Markets

Figure 18 shows the 15 month trend in trade indices or differential to Pool price for the three active reserve products. It can be seen that regulating and spinning reserve indices show a declining trend over the period, suggesting that competitive pressure has increased over the period as more players compete for the same volume of reserves. The figure also shows that supplemental reserves began trading at relatively more reasonable differentials in early August following a revisiting of the notional reserve quantities agreement between the Balancing Pool and TransAlta. As the MSA has noted in previous quarterly reports, and at length in its spinning reserve market report dated January 23, 2004, the prior structure of the notional reserve quantities agreement provided an incentive for TransAlta to have a strong negative influence on the trade index for supplemental reserves in order to mitigate being unable to meet full notional volumes under the agreement. The terms of the new agreement have not been made public.

Figure 18 - Active Trade Indices - (Watt-Ex & OTC)

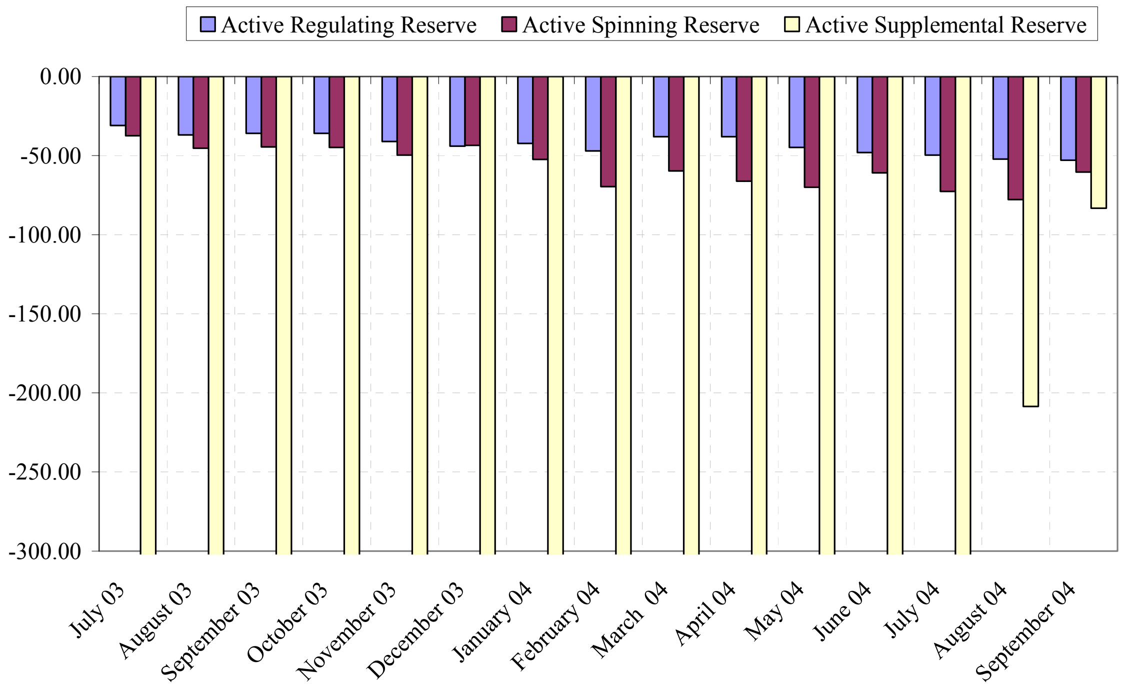
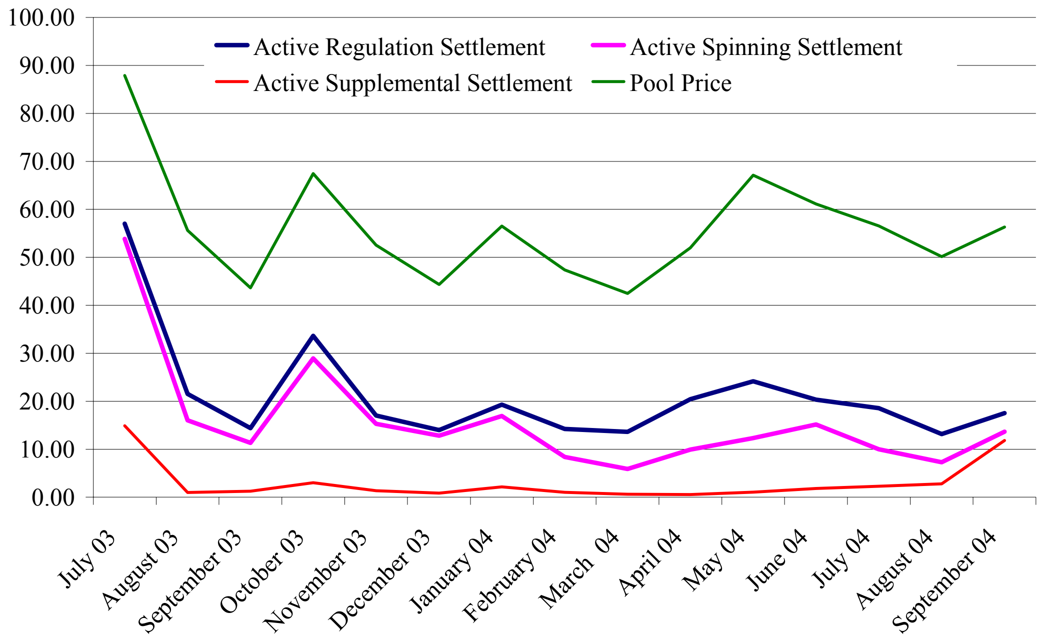


Figure 19 shows monthly average settlement prices for the three active reserve products with monthly average Pool price. Since the price of active products is indexed to Pool price, the settlement prices over the period reflect the overall trend in Pool prices. The figure also shows that the differential in settlement prices between the reserve types narrowed in the month of September. This was due to less discounting of spinning and supplemental reserves relative to regulating, and was most pronounced between supplemental and the other two reserve types. The rebound in supplemental settlements reflects the new trading environment for supplemental reserve post the new PPA reserves agreement between the Balancing Pool and TransAlta.

Figure 19 - Active Settlement Prices - All Markets (Watt-ex and OTC)



Standby Reserve Markets

Unlike active reserve service where normally all active reserves are dispatched, standby reserves are only dispatched when an active reserve provider is unable to perform. Standby reserves are compensated two-fold – a premium and an activation price if the service is called to provide active service. Premiums for standby regulating and spinning reserve are shown in **Figure 20** which indicates little variation in Q3/04 and a relatively tight range since early Q1/04. Standby supplemental premiums moved up through the quarter after reaching a 15 – month low in June of $1.29 / MWh.

Figure 20 - Standby Premiums - All Markets (Watt-ex and OTC)

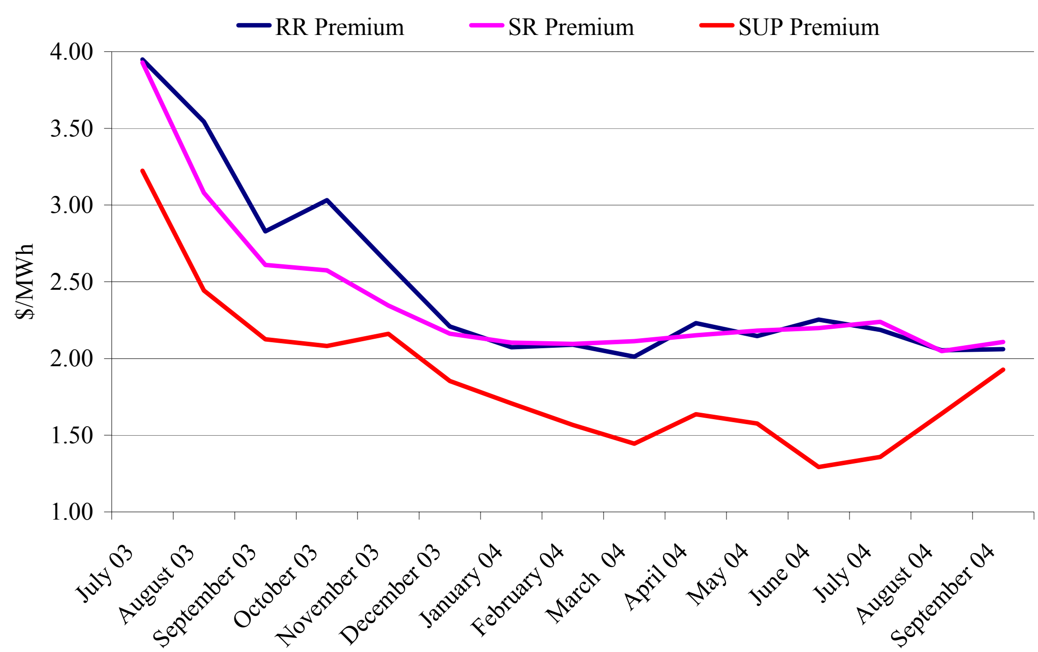


Figure 21 shows Standby activation prices with Pool price over the last 15 months. The figure shows a generally declining trend over the period with an apparent shift in early Q1/04 when regulating and spinning activation prices prior to this point, were generally above prevailing Pool price levels and then below Pool price after this point. This appears to be a function of the activation rates shown in **Figure 22** which reflect a clear reduction in activations for regulating and spinning, and a more modest reduction for supplemental activation rates. Based on a much lower probability of being activated, activation pricing in the standby market has grown much more competitive.

Figure 21 – Activation Prices - All Markets (Watt-ex and OTC)

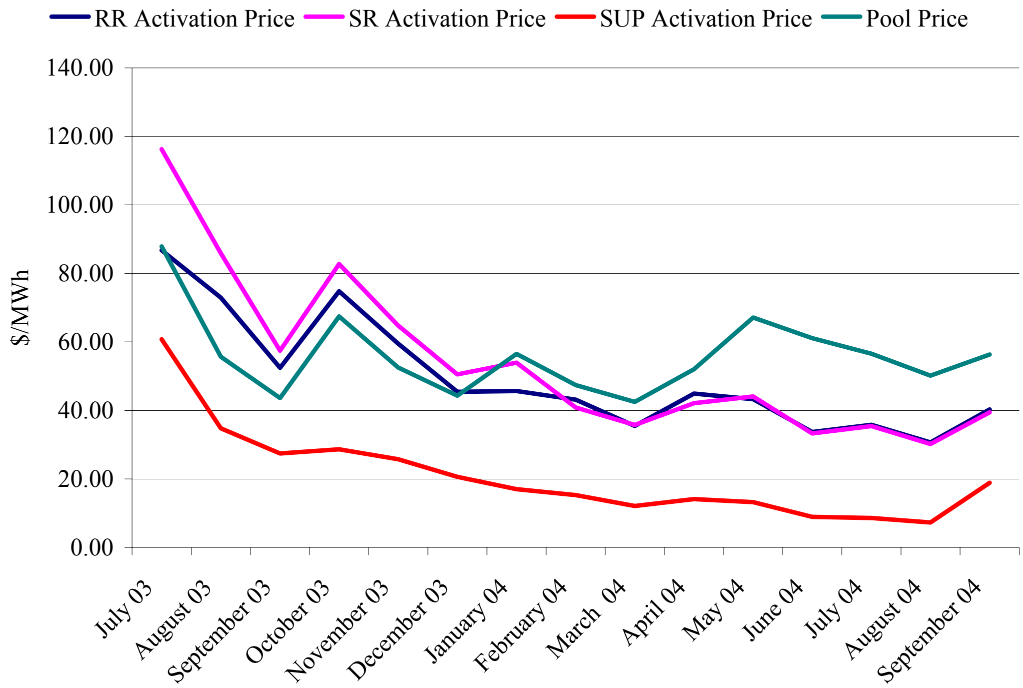
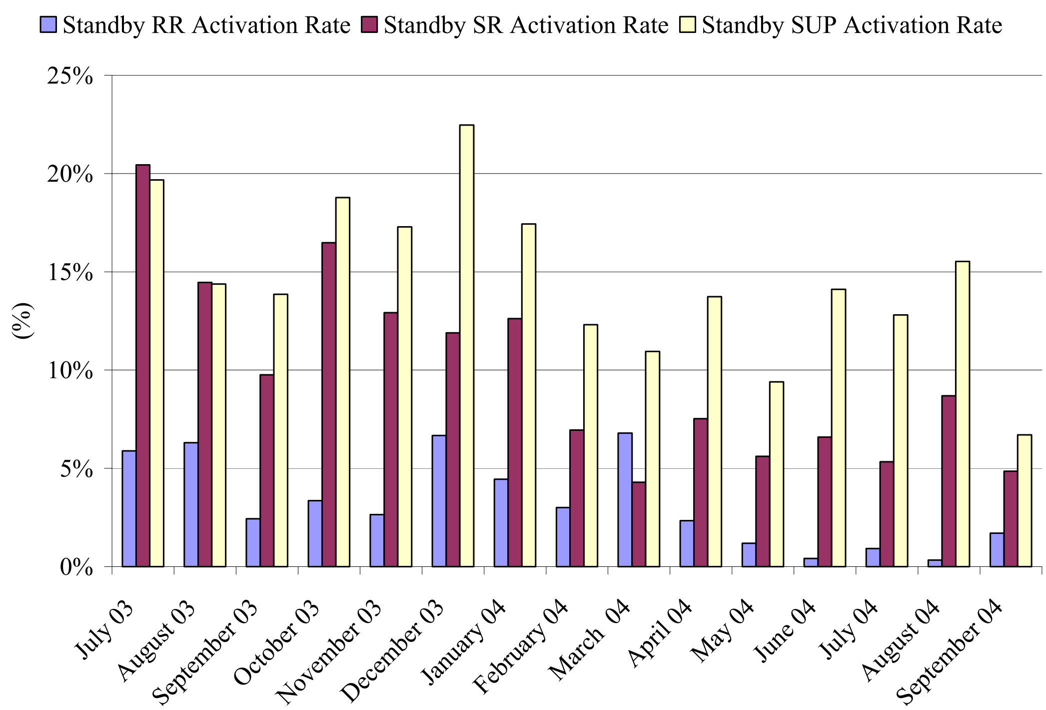


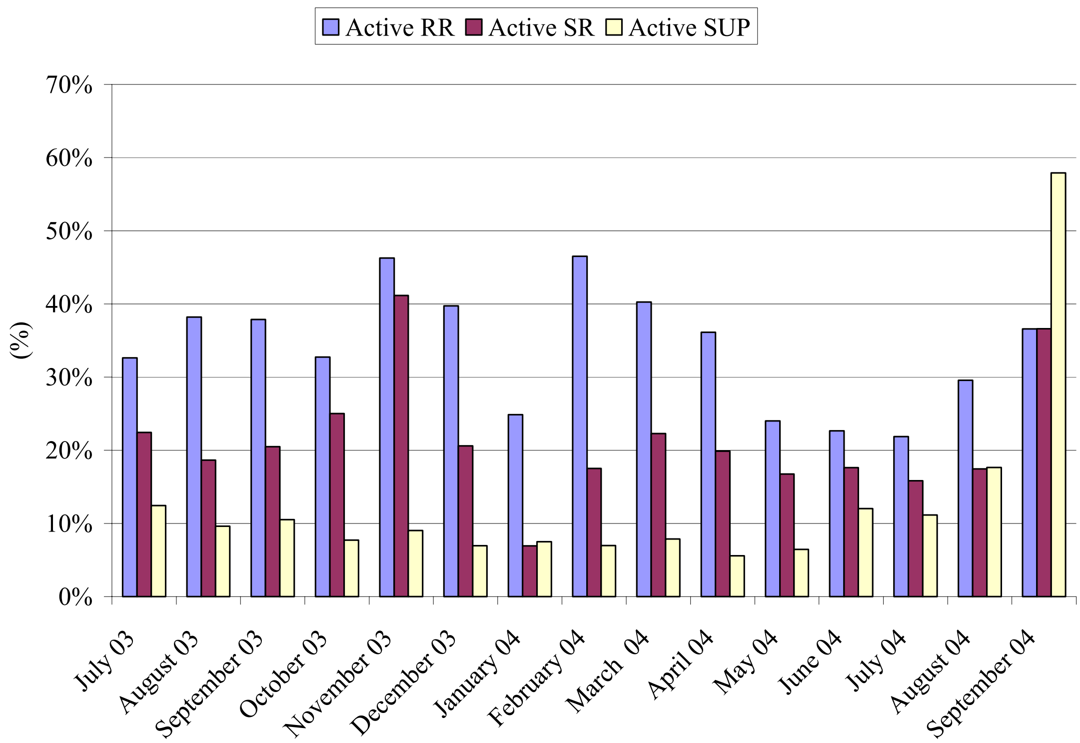
Figure 22 - Standby Activation Rates



OTC Procurement

The AESO procures system reserve requirements via both Watt-ex and directly from counter-parties (OTC). **Figure 23** shows the proportion of volumes that were procured OTC for each active reserve type. While the OTC proportion generally decreased from February to July 2004, it moved up sharply in the balance of Q3/04, particularly with respect to supplemental reserve, where nearly 60% of volumes were procured OTC in the month of September. With the OTC market being a more prominent part of the AESO's procurement strategy, the AESO has increased transparency of this market during 2004 in terms of price and volume data. The MSA continues to monitor the level of OTC transparency to ensure that OTC practices are fair and reasonable to participants.

Figure 23 - OTC Procurement as a % of Total Procurement



Fixed Price OTC Products

Between AESO and Watt-ex, a number of initiatives have been introduced to increase the way in which participants can sell ancillary service products into the market. Fixed contract price is one such initiative that provides both the AESO and the counter-party with price certainty but also serves to shift Pool price risk from the buyer to the seller. Since all Watt-ex traded active reserve contracts are indexed to the Pool price, a differential is locked in rather than a settlement price. **Figure 24** shows that with the exception of February, fixed price volumes for active regulating and spinning reserve have tended to be less than 5% of procured volumes. There were no fixed price volumes procured for spinning reserve in Q3/04.

Figure 25 indicates that fixed price contracts for active regulating reserve were marginally higher than the previous quarter.

Figure 24 - % of Active Regulating and Spinning Purchased at Fixed Price

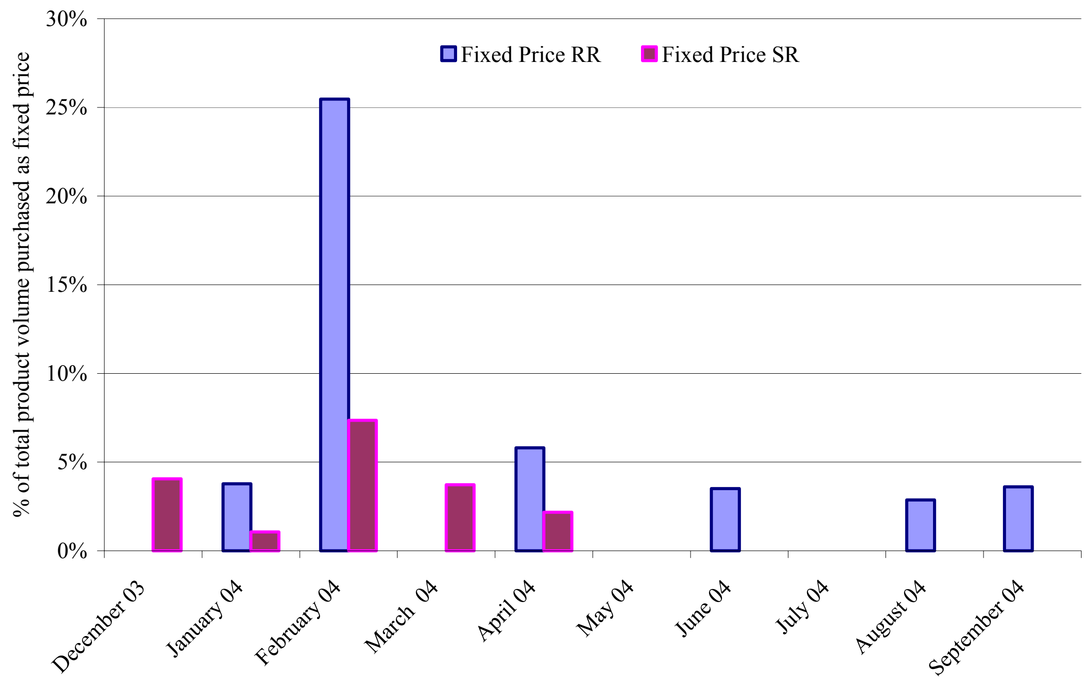
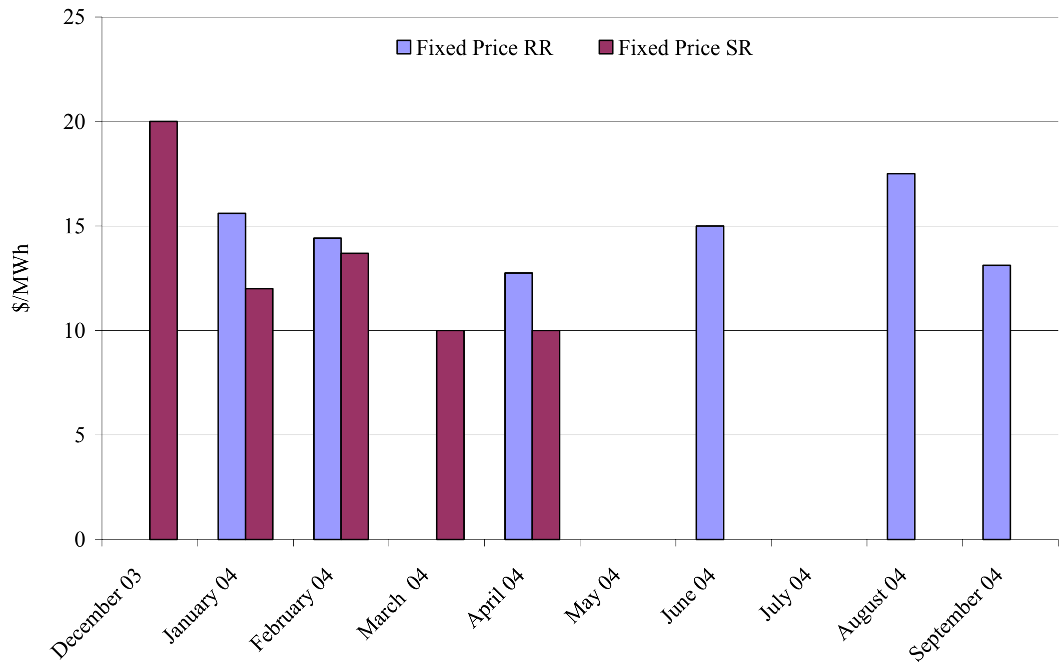


Figure 25 - Active Regulating and Spinning Fixed Prices



Figures 26, 27, and 28 show weighted average settlement prices by market for active regulating, spinning, and supplemental reserves respectively. Generally, OTC procured volumes for regulating and spinning reserve are priced on average, slightly above exchange procured volumes. This is in part, due to requirements by the AESO to procure custom contracts with hourly shaping and which tend to command a premium. The OTC settlements shown in the three figures also include fixed price contracts which may be priced to include a risk mitigation premium.

Figure 26 - Active Regulating Reserve Settlement by Market

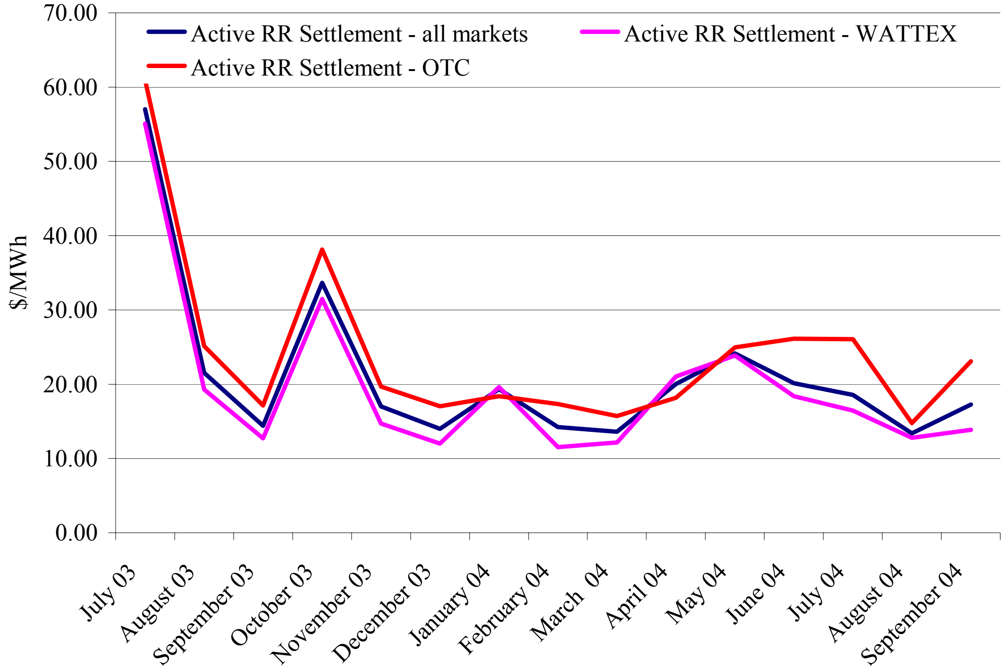


Figure 27 - Active Spinning Reserve Settlement Price by Market

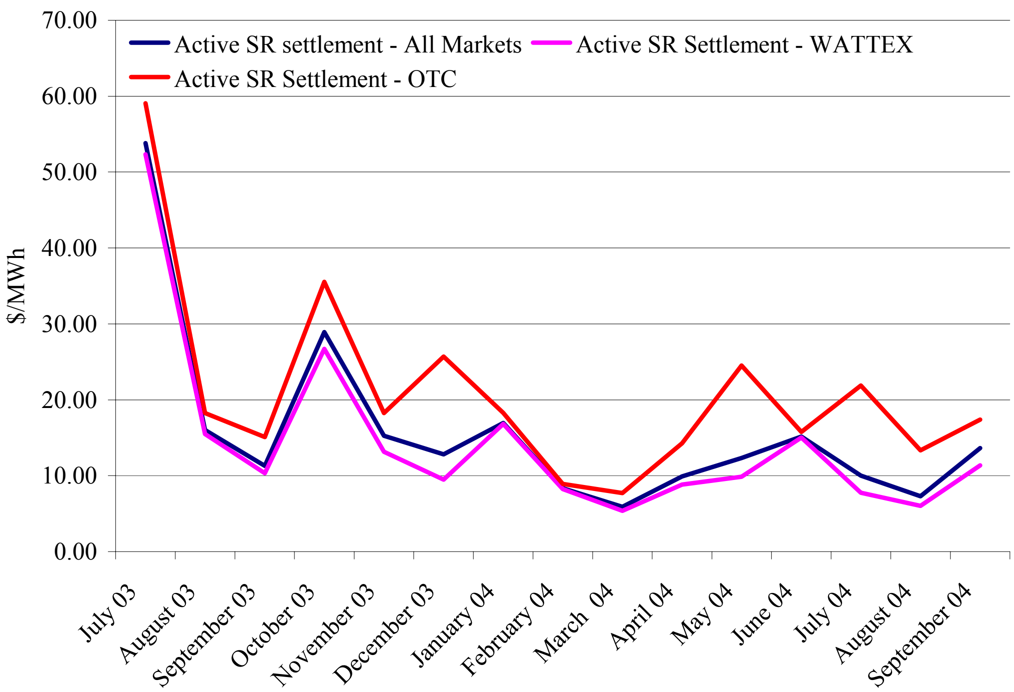
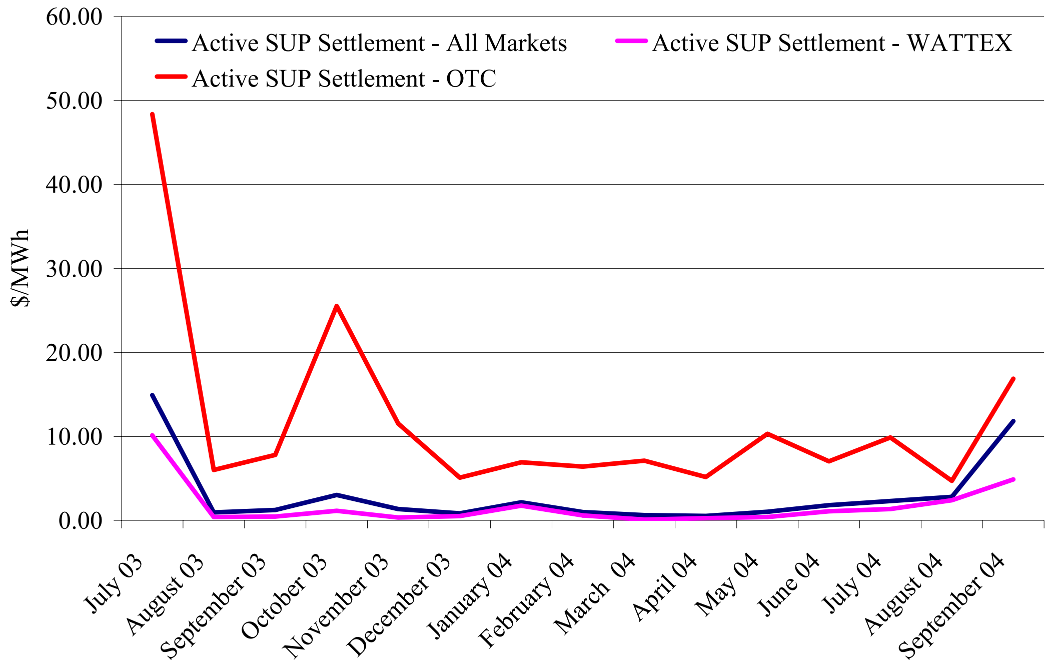
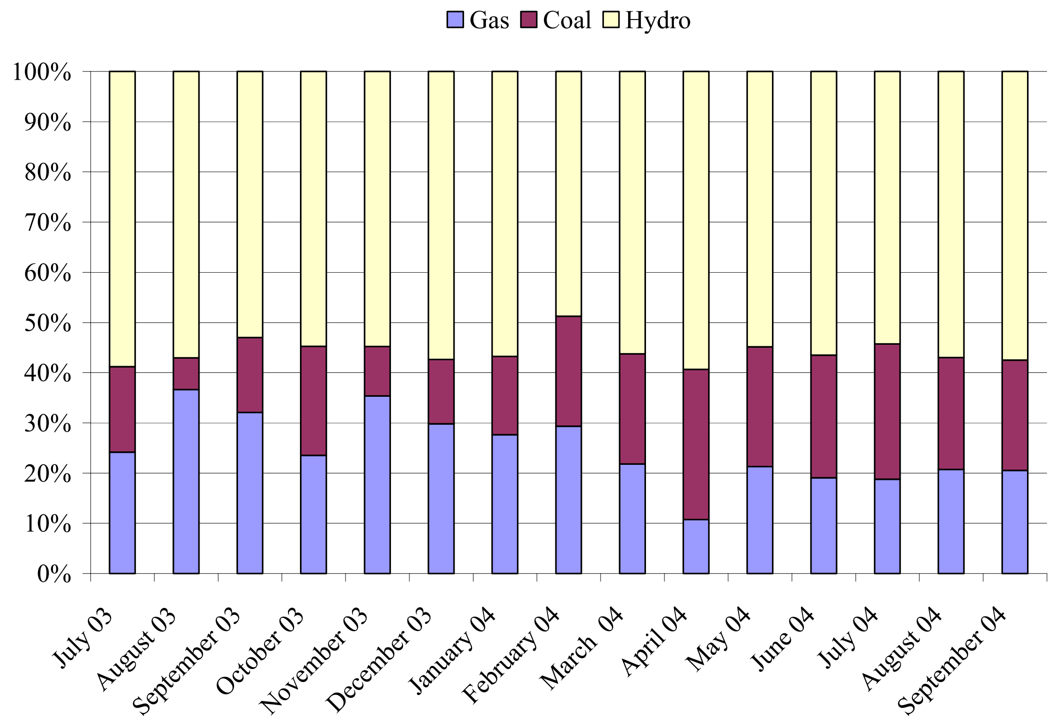


Figure 28 - Active Supplemental Reserve Settlement Price by Market



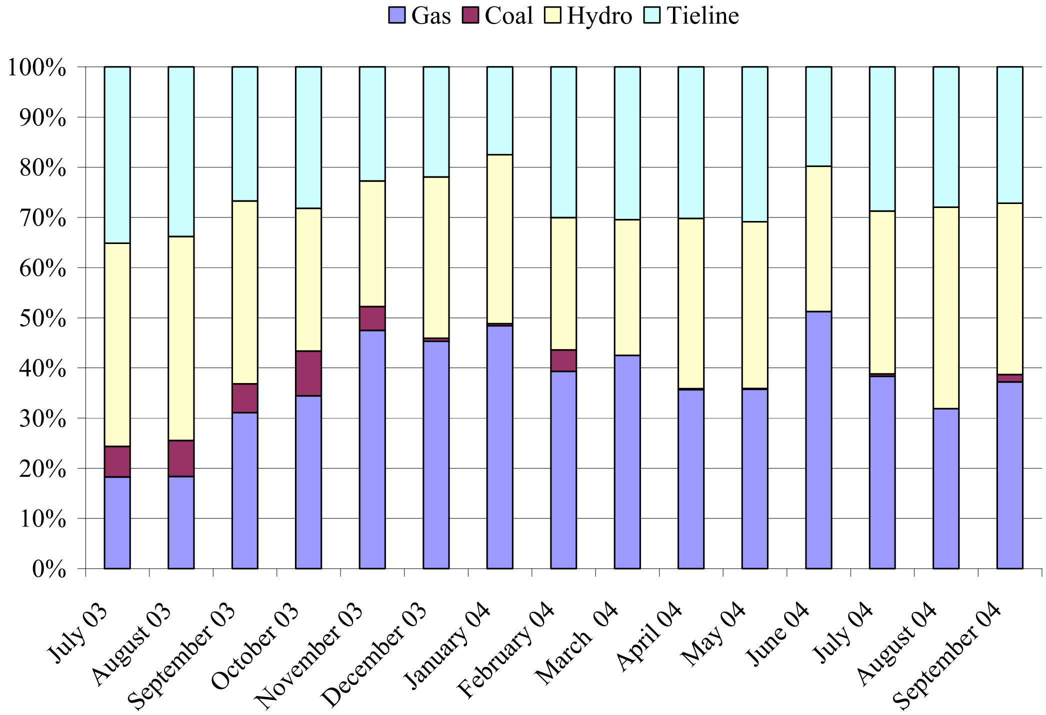
Figures 29, 30, and 31 show the market share distribution for active regulating, spinning, and supplemental reserves by fuel type. In the active regulating market, gas providers continued to maintain about 20% market share since the month of May. Coal providers market share was squeezed marginally from Q2/04 to Q3/04 as hydro market share incrementally increased through Q3/04. In the same quarter a year ago, gas providers had significantly higher share of the regulating market at the expense of the coal units.

Figure 29 - Regulating Reserve Market Share by Fuel Type



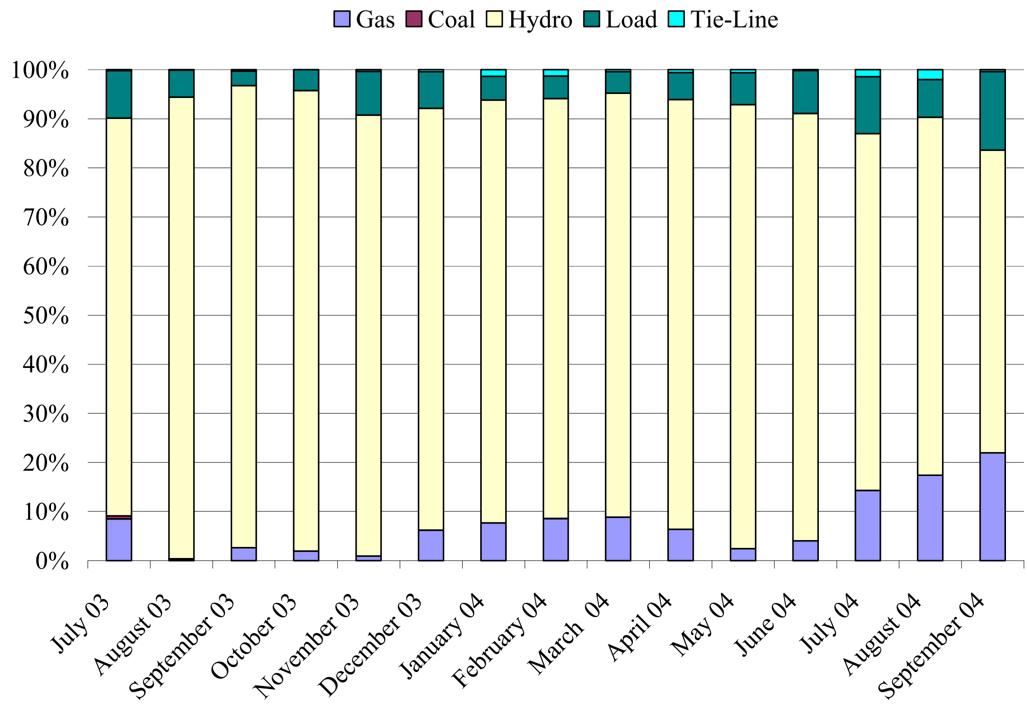
Market shares in the active spinning reserve market remained relatively stable through Q3/04. Tie line market share was essentially flat through the quarter while hydro share increased slightly, taking market share from gas units. Coal tends not to supply a significant proportion of active spin due to the baseload nature of coal plants and the small volumes that are provided tend to be off-peak. In Q3/04 coal supplied less than 1% of active spinning reserve which was similar to the previous quarter but below levels in the same period last year.

Figure 30 - Spinning Reserve Market Share by Fuel Type



Hydro assets are well suited to provide supplemental reserves and thus they dominate this segment of the AS market. Supplemental reserves were the largest proportion of reserves under the previous PPA notional quantities agreement which has since been renegotiated. An outcome of the new agreement is that Hydro share scaled back in Q3/04 although it still provides the large majority of active supplemental reserves. Supplemental reserves provided by load have gradually but steadily increased over the last 15 month period and accounted for 16% of active supplemental reserves in September.

Figure 31 - Supplemental Reserve by Fuel Type



Summary

A key highlight for the AS market in Q3/04 was the outcome of renegotiation of the notional reserve quantities agreement between the Balancing Pool and TransAlta, the operator of the hydro assets. The outcome of the new agreement has been a return of the trading index for active supplemental reserve to "rational" levels since the incentive for TAU's offer behaviour in the supplemental market has been effectively removed. Another impediment to market efficiency has been addressed with respect to disclosure by the AESO of price and volume information for OTC procured volumes. The daily OTC transactions report is located on the AESO website at http://ets.powerpool.ab.ca/Market/reportsIndex.html and selecting Historical/Reports/Daily OTC Transactions.

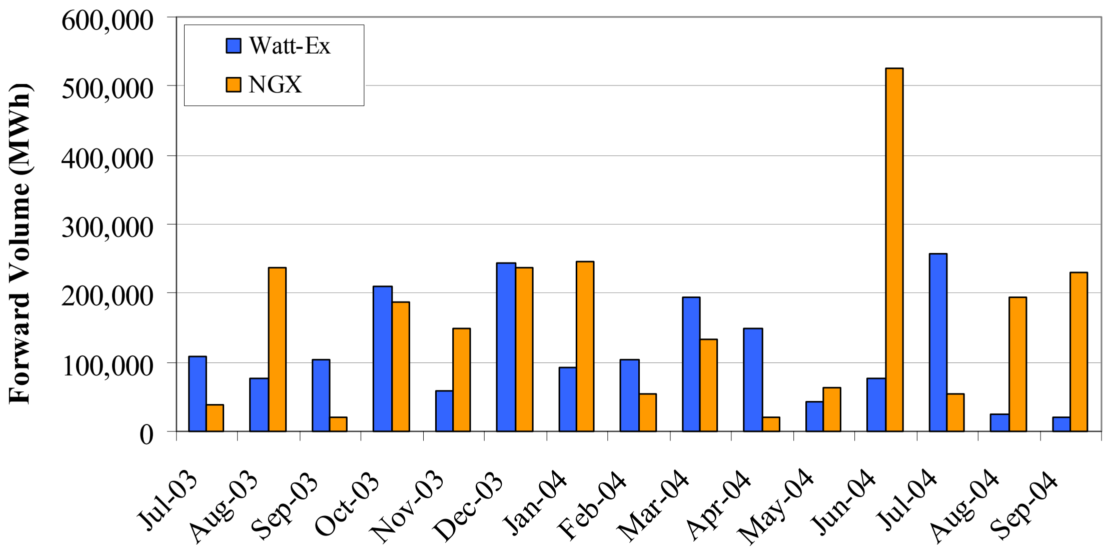
1.10 Forward Markets

Exchange traded forward energy volumes (defined here as Watt-Ex + NGX) were down 11% in Q3/04 as compared to the last quarter but were up 34% relative to the same period a year ago. The significant percentage increase on a year over year basis is primarily attributed to weak NGX volumes in July and September of last year which negatively impacted total exchange traded volumes in Q3/03. Year over year, NGX and Watt-Ex volumes were up 62% and 5% respectively. NGX volumes were down 22% vs. last quarter after a banner quarter in Q2/04 when nearly 610,000 MWh of deal volume was transacted.

As **Figure 32** indicates, Watt-ex volumes have exceeded NGX volumes in selected months, although on a quarterly basis, NGX volumes continued to exceed Watt-Ex traded volumes for the sixth successive period. This is an outcome of more frequent trading of longer term contracts on NGX.

In the context of the physical market, exchange-traded forward energy volumes remains small in comparison, as combined Watt-Ex and NGX traded volumes are about 5% of the physical market.

Figure 32 - Exchange Traded Forward Energy Volume



1.11 Outages and Derates

The MSA continually monitors the outages and derates of generating units in Alberta. Of particular interest are the coal fired 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 and also make up the largest portion of what could be considered "base load" power. When the amount of outage exceeds a unit's historical average, the MSA seeks to understand the cause of the variation.

Figures 33 and 34 illustrate the total outage levels at the coal fired generation facilities, separated by PPA owner. The graphs indicate that outage levels for the third quarter of 2004 are up for two owners from the levels of the last quarter. Owner A has dropped from being the highest last quarter to having the lowest outage levels. Owner C experienced the most outages as a percentage in Q3. However, unplanned outages accounted for nearly 40% of the outages for Owner C. It should be noted that some variation is expected on a year over year basis due to the nature of the multi-year planned outage schedules. When reviewing the historical outages for this owner it was observed that major turnaround maintenance on certain units has not been performed in recent years. With this in mind it should not be considered overly unusual for this level of outage to be experienced. 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 33 – Quarterly Outage Rates by Owner (2004 YTD)

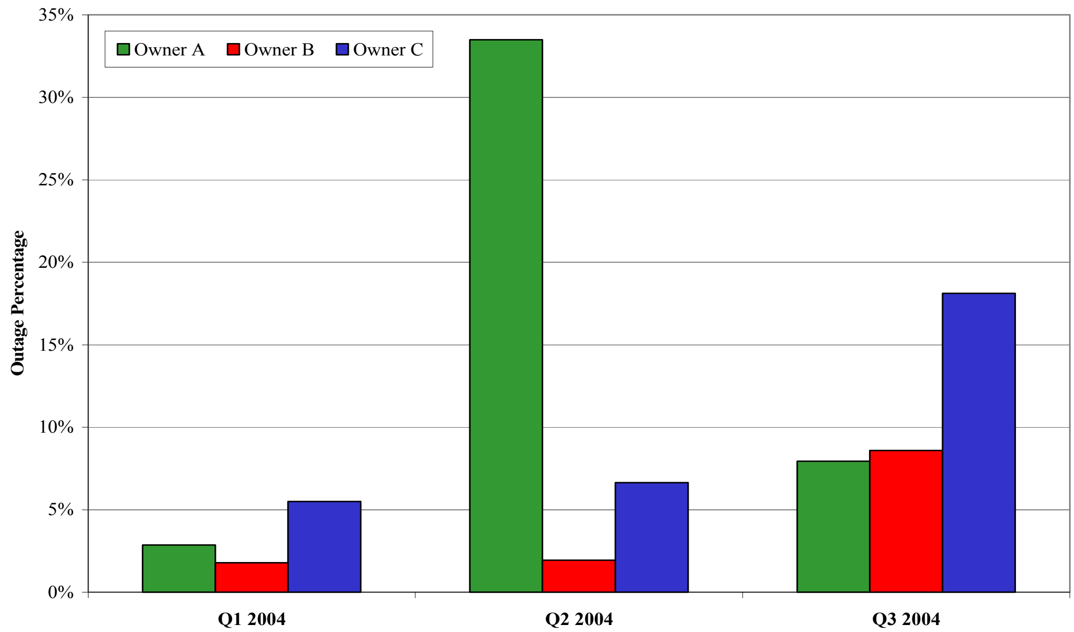


Figure 34 - Quarterly Outage Rates by Owner (Q3/04 vs. Q3/03)

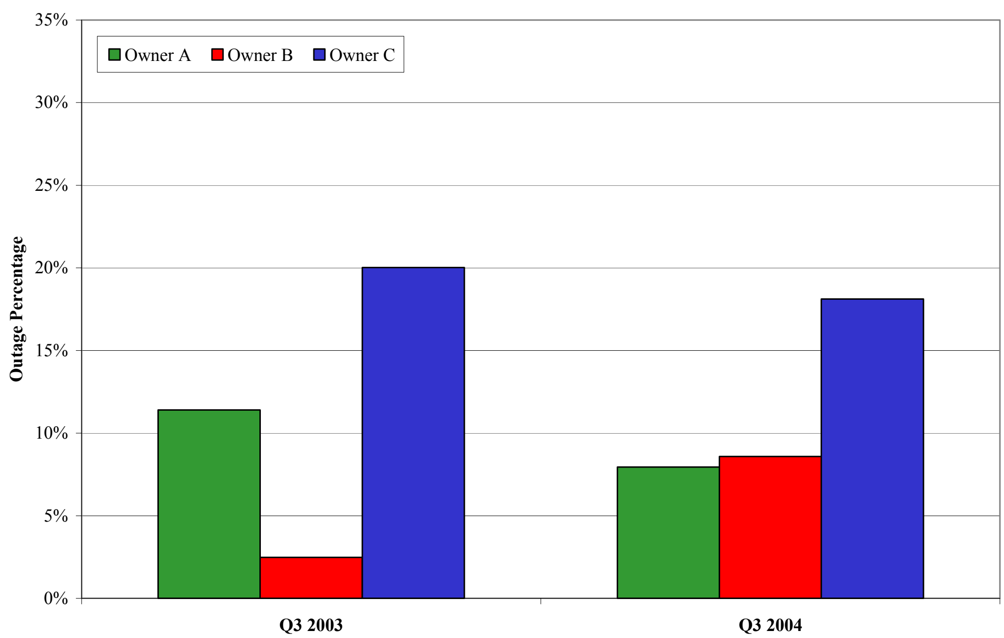


Table 3 reports the unplanned outages on a quarterly basis for 2004. It also provides a look at recent annual unplanned outages for reference. Overall, Q3/04 unplanned outages are below Q2/04 and higher than Q1/04.

Table 3 - Percentage of Unplanned Outages for PPA Coal Units

	Q3/04	Q2/04	Q1/04	2003	2002	2001
Owner-A	**7.4%**	11.7%	2.8%	4.9%	4.2%	3.2%
Owner-B	**1.0%**	2.1%	1.8%	1.5%	0.5%	1.2%
Owner-C	**7.2%**	5.4%	5.5%	5.7%	10.8%	8.8%
PPA weighted average	**6.3%**	6.7%	4.3%	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 and factors such as the unit age and design. By owner, **Table 4** reports the MW weighted average target availability for each coal fired portfolio and the actual availability achieved during 2002 and 2003 along with the present quarter, Q3 2004. The PPA owners normally achieve higher actual availability than their target availability, however in Q3, Owner C was below its target availability. This is not of great concern to the MSA as the target availability is an annual percentage and Owner C is on track to meet this availability target for 2004.

Table 4 - MW Weighted Portfolio Target vs. Actual Availability (%)

	Target Availability	Actual Availability	Target Availability	Actual Availability	Target Availability	Actual Availability
	2002	**2002**	**2003**	**2003**	**Q3 2004**	**Q3 2004**
Owner-A	88%	92%	87%	92%	87%	92%
Owner-B	90%	97%	90%	94%	90%	91%
Owner-C	85%	87%	85%	88%	87%	82%
PPA weighted Average	87%	90%	87%	90%	87%	86%

2 REVIEW OF THE RETAIL MARKET

2.1 Code of Conduct

Compliance Plan Approvals

Compliance plans are required from owners 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.

Depending upon the complexity of the business operations involved, the drafting, review and approval process can require a significant amount of time and effort from the parties before final approval is granted.

In September, 2004, the MSA approved compliance plans for Rocky REA Ltd. and Rocky Rural Power Limited.

Pursuant to a re-organization within the EPCOR group of companies, the MSA approved compliance plans for the following new EPCOR companies: EPCOR Energy Inc., EPCOR Energy (Alberta) Inc. and EMCC Limited. The MSA also approved amended compliance plans for EPCOR Distribution Inc. and EPCOR Merchant and Capital L.P.

As a result of the re-organization, two other EPCOR companies, being EPCOR Energy Services Inc. and EPCOR Energy Services (Alberta) Inc., have been amalgamated with EMCC Limited. As such, their related compliance plans ceased to have force and effect as at September 1, 2004.

As at the end of September, 2004, a total of 14 compliance plans stand approved.

Interim Approvals – Review

As previously reported, in December, 2003 the MSA issued interim compliance plan approvals for Aquila Networks Canada (Alberta) Ltd., ENMAX Energy Corporation, ENMAX Power Corporation, EPCOR Distribution Inc., EPCOR Energy Services Inc., EPCOR Energy Services (Alberta) Inc. and EPCOR Merchant and Capital L.P., based upon compliance plan filings received to that point.

The interim approvals allowed those parties to meet the requirements of the Code and undertake retail activities while work continued toward full compliance plan approval. The interim approvals carried terms and conditions, including the requirement for additional reporting. Each of the parties ultimately obtained final approval for their compliance plan during the month of June, 2004.

In relation to the interim approvals, the MSA has undertaken an audit type review of the operations and conduct of each of those parties for the period January 1 through June 30, 2004. The review is intended to provide further assurance that the parties adequately met the other requirements of the Code despite their failure to obtain final compliance plan approval on a timely basis. Coincidentally, the review should complement the regular audit requirements of the parties for that portion of the 2004 calendar year.

The MSA has retained Grant Thornton LLP to assist in the review.

Code of Conduct Audits 2005

During Q3 2004, the MSA undertook planning discussions with parties who will be subject to the audit requirements under the Code for the 2004 calendar period. In response to a common desire to make the audits as cost and resource efficient as possible, the MSA has proposed that the next regular Code audits should occur at the end of Q2 2005, rather than during Q1 2005. This initiative is intended to address concerns raised by various parties about the difficulties caused by having the Code audits occurring during the first quarter of each year, when financial audits and tax matters are also at the forefront.

Further, and in concert with the review and other matters described above, the MSA intends that the Code audit period will move from a calendar year approach to a period being July 1 through June 30. Among other things, this will place the annual audit close in time to the period under review.

Finally, the MSA is also examining the benefits of having all of the regular Code audits conducted by one independent audit firm retained by the MSA, and utilizing one common audit plan, rather than having each of the parties seek approval for its own auditor and audit plan. Again, the intent is to make the audits as efficient and effective as possible.

The MSA is continuing its discussions with the various parties who would be directly affected by these initiatives.

Access to Customer Information

The MSA has been participating in discussions with representatives of the Department of 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 goals of the MSA are to further the fair, efficient and openly competitive operation of the retail market.

The discussions to date have been at a high level, and will continue over coming months under the lead of the EUB. These discussions may ultimately impact the manner in which customer information is handled under the Code. It is important to stress, however, that protection of the interests of the customer has been and will remain a paramount consideration in the discussions and in any changes which may result from this initiative.

2.2 Retail Market Metrics

The MSA continues to track performance in the retail market based on the following metrics:

- Number of active retailers
- Retailer entry and exit from the market
- Market share of retailers (with respect to load)
- Trends in customer switching off the Regulated Rate Tariff (RRT) to sign competitive contracts.

As of September, 2004 there were 113 active retailers in the Alberta electricity market, 78 of which are self-retailers. Some of the larger retailers have individual companies that are classified as separate entities for financial reporting reasons but are essentially the same organization under a single brand.

Figure 35 - Retailer Market Share by Load (Q3/04)

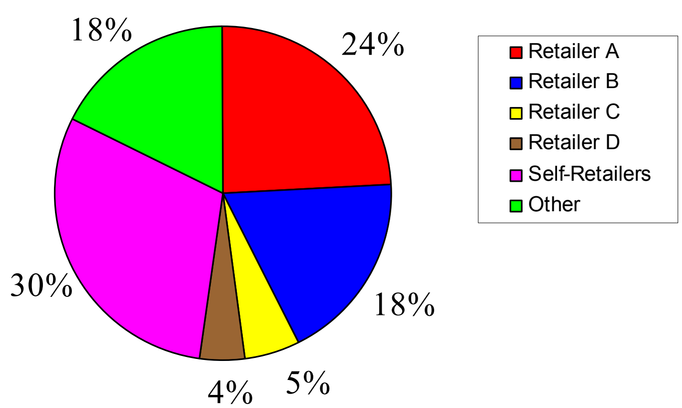
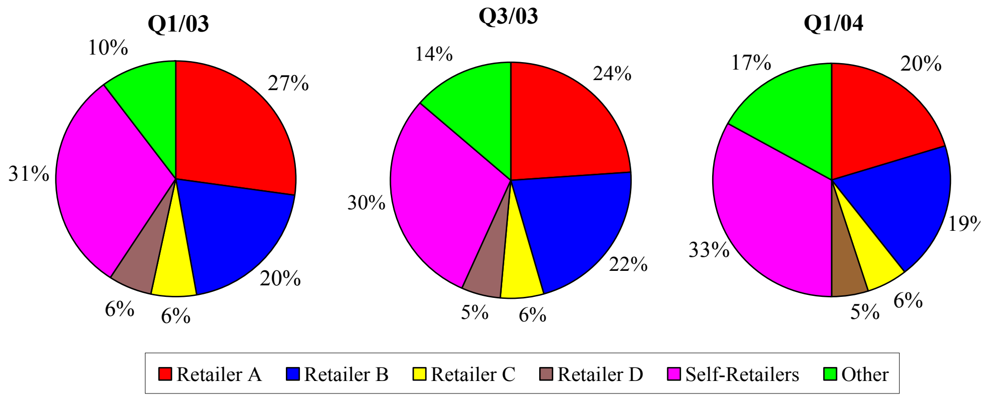


Figure 35 shows the overall provincial market share of retailers for Q3/04. The largest four retailers are servicing over 51% of the total provincial load. Self-retailers, usually large industrial organizations, make up another 30%, while assorted smaller retailers are competing for the remaining 18% of the market.

Over the past quarter, we have seen a notable change in distribution of the market shares as the cumulative market share of retailers with at least 4% market share has increased (retailers A, B, C and D). This is largely due to Retailer D gaining sufficient market share to break out of the "Other" category.

Figure 36 - Historical Market Share of Retailers by Load



Note: Retailer labels do not necessarily represent the same retailer for each quarter.

Figure 36 provides a biannual look at the changes in market share since the beginning of 2003 which demonstrates a modest trend away from larger retailers towards smaller retailers. The above figure shows a gradual deterioration trend in the two largest retailers and a slight growth in the smaller retailers and "other" retailer categories. This movement is an encouraging sign of competition as customers seek new retail services from smaller firms in 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 37 – Q3/04 Market Share of Retailers by Customer Class

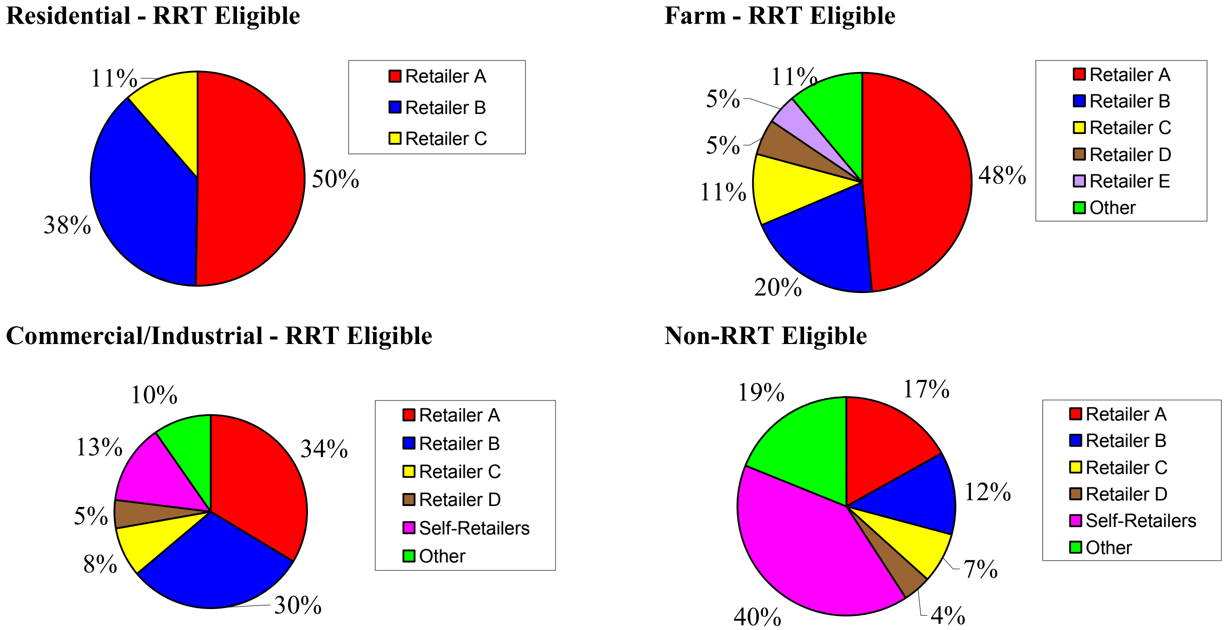
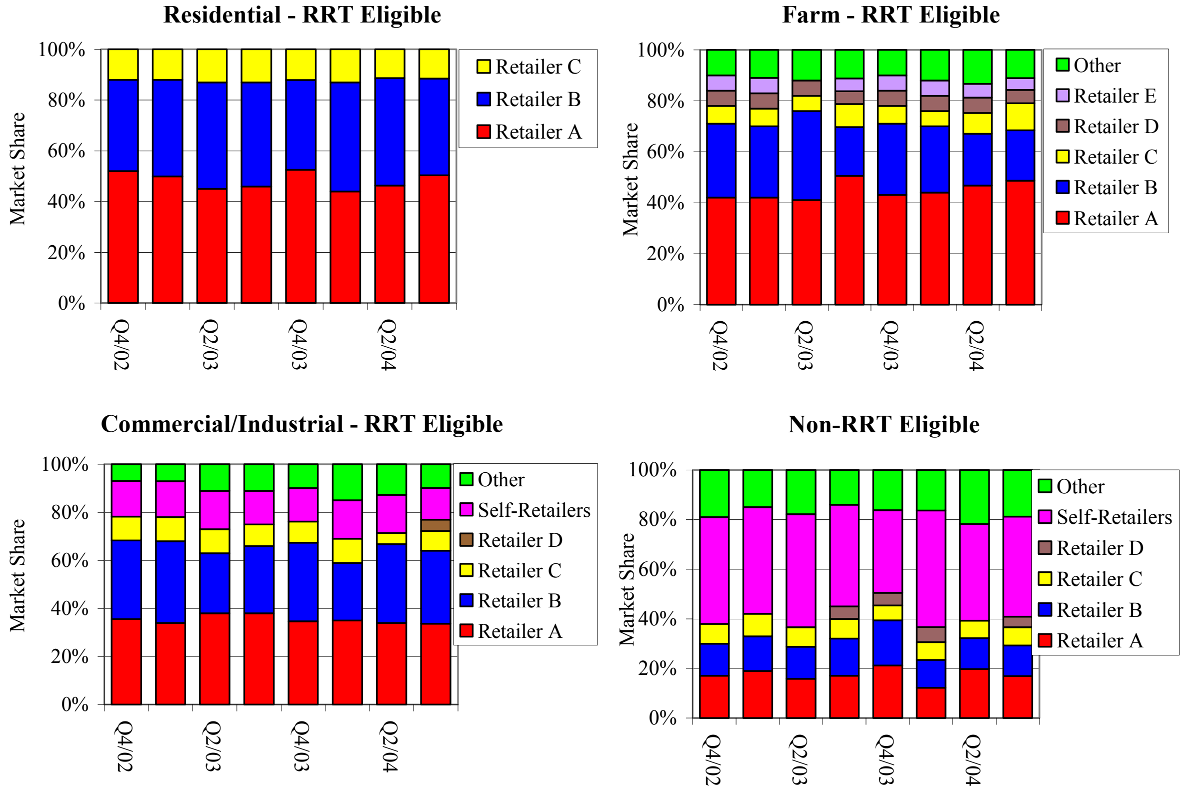


Figure 37 shows retailer market share by customer class for Q3/04. Market shares of the main retailers in the Commercial/Industrial – RRT Eligible category have declined slightly and allowed for other retailers to gain ground in this category. The cumulative market share of the four retailers with at least 4% market share adds up to 77% of the total load. Again, a trend towards to "self retailing" seems appealing to those wishing to have more control over the energy portion of their business.

Figure 38 is another way to look at the shift in market share in the 4 categories. The picture is useful in providing an overall view of the change in market share over the past two years and demonstrates the dynamic nature of 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 our retail market.

Market shares of the three dominant retailers in the Residential – RRT Eligible class have not substantially changed over the two years. There has been some jockeying for position between the two largest retailers, but over the past eight quarters the cumulative market share of these two retailers has ranged between 87% and 90%. Market shares of the dominant retailers should decrease as more residential retailers enter the market and attract customers away from the incumbent retailers. In the Farm – RRT Eligible category, market shares have also remained fairly static. However, some REA's are becoming more involved in retailing and may have a noticeable effect on market shares in the Farm - RRT eligible category.

Figure 38 - Progression of Retailer Market Share by Customer Class



The overall progression of customer sites away from the RTT to competitive electricity contracts has held relatively steady, as can be seen in **Figure 39**. As of September 30, 2004, 6.8% of all RRT eligible customer sites have chosen to enter into a competitive contract with a retailer.

Figure 39 - Progression of RRT Eligible Sites Switching Off RRT

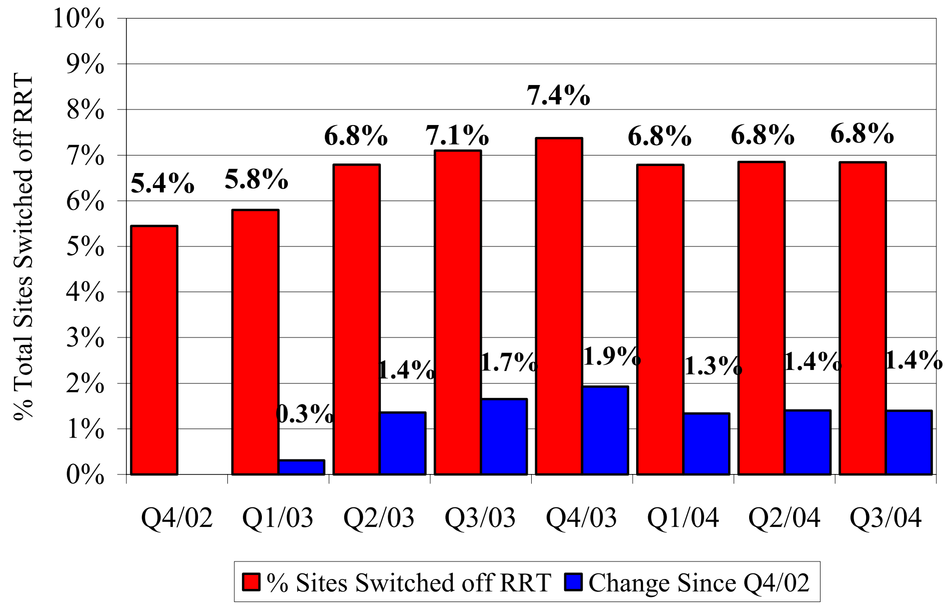
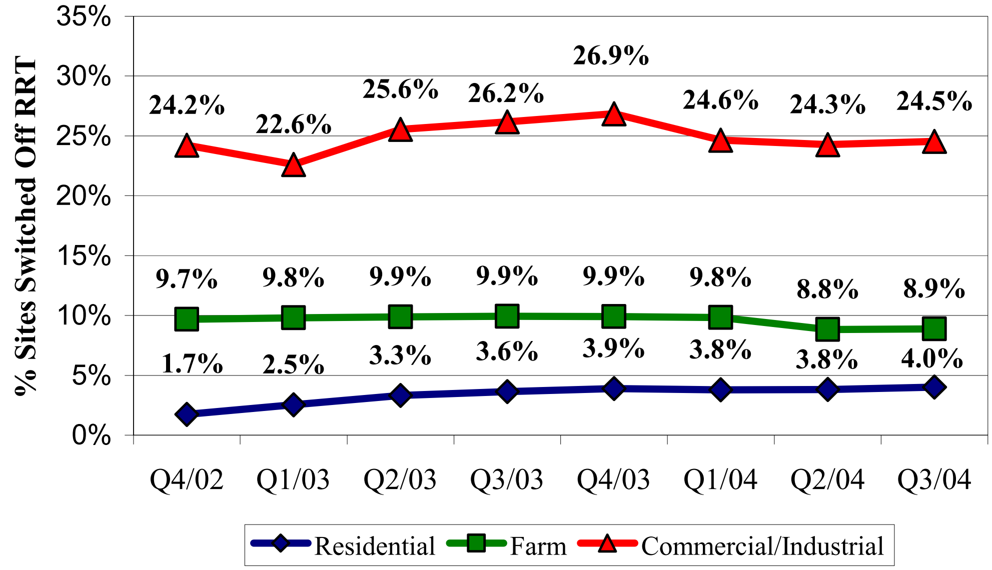


Figure 40 shows the segmentation by Customer type, of the aggregate switching data shown in **Figure 39**. Switching results are encouraging in the residential category where switching rates have increased slightly by 0.2% from 3.8 % in Q2/04 to 4.0% in Q3/04.

Switching rates in the Commercial/Industrial – RRT eligible category are holding relatively constant and is now at the level of 24.5%. During Q4/03, a change in policy pushed back the deadline for Commercial/Industrial – RRT Eligible customers to choose a competitive contract or be subject to Pool price flow-through from the end of 2003 to July 1, 2006. This change in policy could be the driving force behind the decreased switching rates observed in Q1/04.

Figure 40 - Progression of RRT Eligible Sites Switching Off RRT by Customer Type



Please note that the switching rates previously reported for Q1/04 and Q2/04 were incorrect and have been revised in this report. The MSA strives to be accurate and regrets any inconvenience this error may have caused.

2.3 Settlement System Code Monitoring

The MSA continues to monitor the Settlement System Code (SSC) with the intent of the assessing how well settlement is working in Alberta.

The MSA has developed a number of metrics related to settlement and enforcement of the SSC. The metrics are intended to be indicators of potential problems with the settlement process. As detailed monitoring of settlement and compliance to the SSC is the role of the AESO, the MSA's observations will tend to be more directional in nature, identifying trends in the settlement process.

Complaints

The SSC uses PFECs, PFAMs and Notices of Dispute as tools to resolve financial disputes resulting from settlement calculations. PFECs occur before final settlement while PFAMs occur after final settlement. Notices of Dispute are used when two parties disagree over the results of a PFAM. Statistics regarding the number of PFEC/PFAMs submitted, accepted and rejected were collected from the four load settlement agents (LSAs) in the province. **Table 5** summarizes PFEC and PFAM tracking for Q3/04.

Table 5 - PFEC and PFAM Tracking

Claim Type	Carry-Over	Submitted	Accepted	Rejected	Unresolved	Net kWh Adjustment
PFEC						
Q2/04	32	396	307	19	102	NA
Q3/04	102	1,204	337	12	957	NA
PFAM						
Q2/04	1,409	296	708	674	323	(9,535,801)
Q3/04	323	134	229	91	137	94,633,426

The table shows that the number of PFECs submitted has increased substantially from last quarter. This can largely be attributed to a single LSA that is correcting an IT issue. It is expected that this will be corrected before the end of the year and the majority of the unresolved PFECs will be dealt with. This will continue to be closely monitored by the MSA to ensure the PFECs are dealt with in a timely manner.

The volume of PFAMs has declined during Q3/04. The decreasing number of PFAMs is an indicator that the LSAs are improving their processes for dealing with complaints and are being proactive in resolving issues before final settlement occurs.

Over the past three months, two separate Notices of Dispute have been forwarded to the MSA. Notices of Dispute are used to initiate the dispute process as outlined in the SSC. This process requires parties involved in the dispute to notify the MSA of the negotiation efforts that have been made to resolve the dispute. If a dispute can not be resolved by negotiation or mediation, binding arbitration can be pursued and the MSA will be made aware of the outcome.

UFE

The MSA also collected data regarding UFE in the form of UFE Reasonable Exception Reports for each of the 10 settlement zones in the province. These 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 6** summarizes the UFE Reasonable Exception Reports (UFE reports) filed over the last two quarters.

Table 6 - Summary of UFE Reasonable Exception Reporting

Quarter	Outstanding (from all previous quarters)	New	Resolved	Unresolved
Q2/04	13	8	3	18
Q3/04	18	3	2	19

At the end of Q2/04 there were 18 unresolved UFE reports. By the conclusion of Q3/04 this number increased by 1, to 19. This shows that the LSAs are not dealing with exceeded UFE tolerances in an efficient manner[3]. Not only are the new UFE reports not being resolved within the quarter in which they were submitted, but it does not appear that outstanding UFE reports are being resolved over the course of the past two quarters. We would expect to see improvement in the resolution of these UFE issues before the end of 2005.

Non-Compliance, Enforcement Escalation and Enforcement Withdrawal Notices

In late 2003 the AESO initiated an enforcement ladder for the SSC[4]. 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.

The MSA started collecting this data in 2004. **Table 7** summarizes the Non-Compliance, Enforcement Escalation and Enforcement Withdrawal Notices filed by the AESO in 2004.

[3] Some unresolved UFE reports are attributable to the implementation of new systems at one LSA while others are attributable to system level errors.
[4] See Section 4 of Appendix C of the SSC.

Table 7 – 2004 Non-Compliance, Enforcement Escalation and Enforcement Withdrawal Notices

	Non-Compliance Notices Issued			
	Level 1	**Level 2**	**Level 3**	**Level 4**
January	0	0	0	0
February	4	0	0	0
March	1	1	0	0
April	0	0	0	0
May	0	0	0	0
June	0	0	0	0
July	0	0	0	0
August	0	0	0	0
September	1	0	0	0
YTD Total	**6**	**1**	**0**	**0**

The table shows that to date six Level 1 Non-Compliance notices and one Level 2 Non-Compliance notice have been issued by the AESO. This appears to indicate that overall compliance with the SSC is going well.

3 MARKET ISSUES

3.1 TPG / IDP Update

On June 28, 2004 the MSA published a final draft of the Information Disclosure Procedures (IDP) to the MSA website at (TPG and IDP Initiatives - June 28, 2004). The Information Disclosure Procedure (IDP) is in support of the Trading Practices Guideline (TPG). In particular, the IDP is designed to assist market participants with their TPG compliance requirements by facilitating the disclosure and publication of outage and derate information. In addition to outlining the disclosure requirements, the notice included a summary of discussion items from the workshop and a list of future activities concerning the TPG and IDP.

The future activities included were:

- The MSA will resume publishing the reports on July 5, 2004.
- The MSA will continue to investigate a single data aggregation methodology that works for all units and accurately reflects the operating characteristics of each unit.
- The MSA will continue to work with the AESO on identifying the types of transmission assets and events that should be incorporated into the IDP.
- Over the next several months the MSA will be working with the LSAs in order to identify relevant load assets.
- The MSA will monitor the 40 MW threshold level as it pertains to load.
- The MSA will work with the AESO to develop the required systems to facilitate a web based system capable of being updated anytime there is a change in the amount of outages scheduled.

The MSA is currently preparing an IDP/TPG status report that outlines the progress on the 6 activities above and comments on other issues such as success metrics and investigations.

Given the amount of detail included in the update, the MSA will be posting a separate TPG / IDP document to the MSA website.

3.2 Uneconomic Imports & Exports

The MSA has undertaken a review of uneconomic import and export activity on the BC tie line, the preliminary results of which were presented at the fall stakeholder meetings. This project was initiated in part to address concerns expressed in the market that parties systematically import or export energy at a loss in order to influence Pool price to suit their portfolio position. The first stage of the MSA's work involved the determination of the basic economics of imports and exports over a 19 month period. Further work remains and the conclusion of this work is anticipated during Q4/04.

3.3 Regulating Reserve Study

As noted in the Q2/04 report, the MSA undertook a comprehensive study into the System Controllers use of regulating reserves which was completed and presented at the fall stakeholder meetings. The study concluded that there was no evidence to support the allegation that system controllers "lean" on regulating reserve in order to avoid dispatching up the merit order. The report indicated that the actions of system controllers are attributed to managing area control error or ACE in order to prevent CPS2 violations and that the strategies of system controllers in minimizing these violations coupled with the lack of dispatch fidelity on behalf of generation and load have lead to a stable sub-optimal outcome. The report contains the full analysis leading to the MSA's conclusions and the reader is encouraged to review this report at www.albertamsa.ca .

3.4 Retail Metrics

For the past year, with the assistance from the LSA's, the MSA has developed a set of retail market statistics and published the results in these quarterly reports (see section 2.2). The MSA is currently engaged in discussions with retailers to see what enhancements might be possible so as to make the information more valuable to them. The MSA expects to conclude this exercise by the end of 2004.

4 OTHER MSA ACTIVITIES

4.1 Stakeholder Presentation

The MSA held its fall Stakeholder meetings on September 29th in Calgary and on October 5th in Edmonton. The meetings were well attended and the presentations given have been posted to the MSA website at www.albertamsa.ca.

4.2 MSA Presentation to Long-Term Adequacy Task Force

The MSA supports the mandate of the Long-Term Adequacy Task Force and recently gave a presentation to the group which can be viewed at http://www.albertamsa.ca/files/ResourceAdequacyandPriceSignalQuality(1).pdf

4.3 Electricity Market Television Production

The MSA participated with four other industry stakeholders – the Independent Power Producers Society of Alberta, the Alberta Electric System Operator, the Utilities Consumer Advocate, and EPCOR, in a 30 minute television production aired on Access in late Q3/04, covering the restructured electricity market. The MSA's segment of the program has been posted to the MSA website and all other segments of the program can be viewed at www.reganproductions.com/rea_tuneinto_restructmarketplace.html.

4.4 Regular Report Feedback

Market Stakeholders are encouraged to submit their feedback on the MSA quarterly report, as well as any other regular report published by the MSA. Please direct your comments or suggestions to: MSAinformation@albertamsa.ca.