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MSA REPORT

Quarterly Report

April - June, 2004

29 July, 2004

MARKET SURVEILLANCE
ADMINISTRATOR

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Market Highlights

- The average price of electricity in the Alberta wholesale spot market in Q2/04 was $60.07/MWh which compares to $48.81/MWh for Q1/04 and $50.94/MWh for Q2/03. The implied heat rate for the quarter increased to 9.1 GJ/MWh from 8.0 GJ/MWh in Q1/04, and this was also ahead of the same quarter a year ago when the implied heat rate was 7.9 GJ/MWh.

- TPG / IDP continued to move forward as the MSA held a stakeholder meeting in June to solicit additional feedback on this initiative and its implementation. The MSA has recently resumed publication of outage reports.

- The MSA commissioned a survey in Q2/04 to gather stakeholder views on the effectiveness of our agency in fulfilling its mandate and responsibilities. Details of the survey are discussed herein and the summary report is available for download on the MSA web site at www.albertamsa.ca .

1 REVIEW OF THE WHOLESALE ELECTRICITY MARKET

1.1 Electricity Prices

Wholesale electricity prices moved higher in Q2/04 relative to both the previous quarter and the same period a year ago. Prices were higher in Q2/04 on both an on-peak and off-peak basis as shown in **Table 1**. May was the highest priced month of the quarter with an average on-peak price of $80.44/MWh and this was largely attributed to the onset of maintenance season for generators and the resulting drop in base-load coal unit availability coupled with gas prices reaching a 15-month peak in the month of May. The price duration curves in **Figure 1** show that prices in Q2/04 were higher than in Q1/04 the majority of the time, however the frequency of prices above $100/MWh was approximately equal. In general, it can be seen that the price duration curve is flatter for Q2/04 and this is reflected in lower volatility metrics relative to Q1/04 and Q2/03. These curves also demonstrate why Q2/03 had higher price volatility metrics as compared to the two more recent quarters shown, since it produced a wider distribution of prices. **Figure 2** suggests that price volatility has been modestly trending down over the last 15 months.

Table 1 - Pool Price Statistics

	Average Price	On-Pk Price	Off-Pk Price	Std Dev[1]	Coeff. Variation[2]
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%**
Jan - 04	56.51	66.61	42.53	61.98	110%
Feb - 04	47.38	50.13	43.99	49.20	104%
Mar - 04	42.46	48.50	34.09	33.80	80%
Q1 - 04	**48.81**	**55.08**	**40.20**	**50.02**	**102%**
Apr - 03	51.68	62.57	36.71	50.74	98%
May - 03	56.50	69.57	39.94	62.87	111%
Jun - 03	44.47	59.57	25.59	59.25	133%
Q2 - 03	**50.94**	**63.90**	**34.08**	**58.09**	**114%**

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

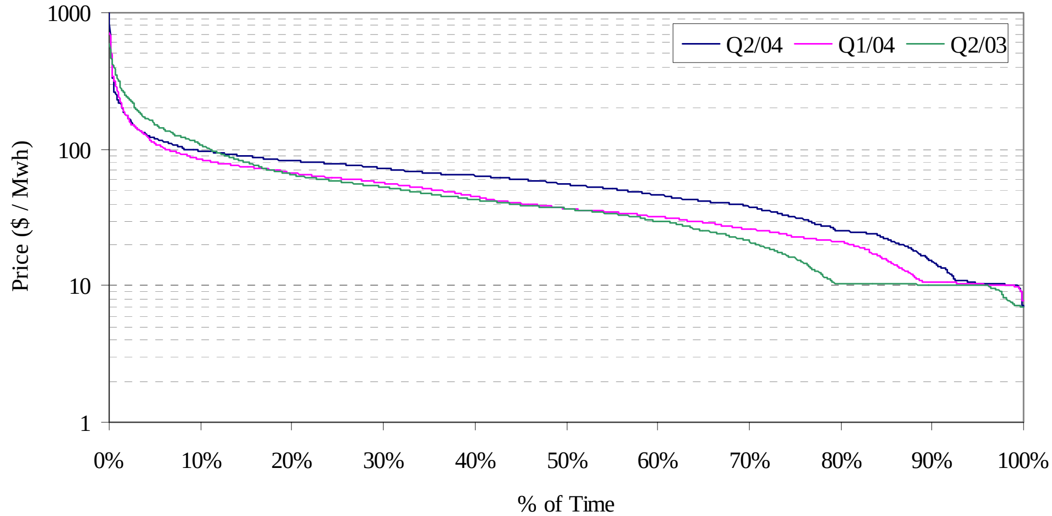
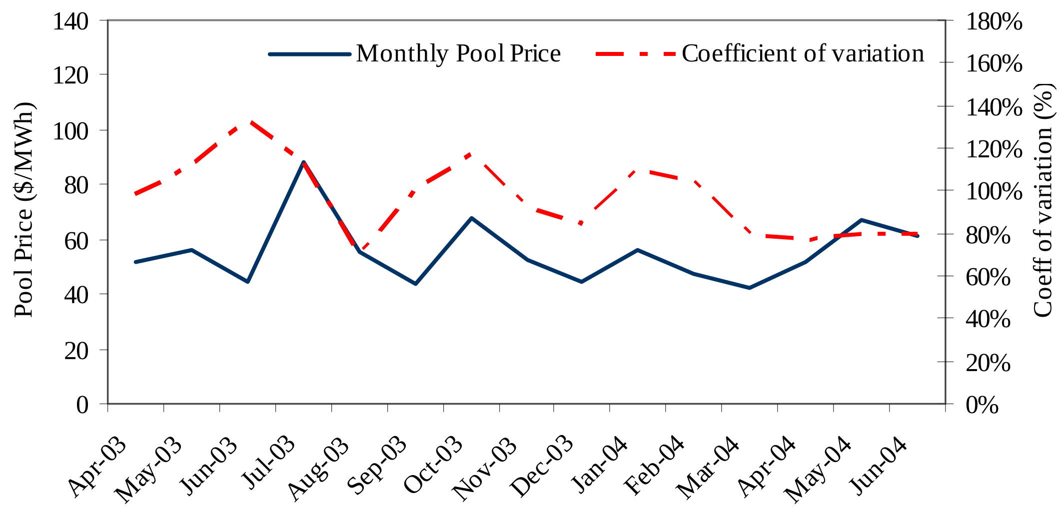


Figure 2 – Pool Price with Pool Price Volatility

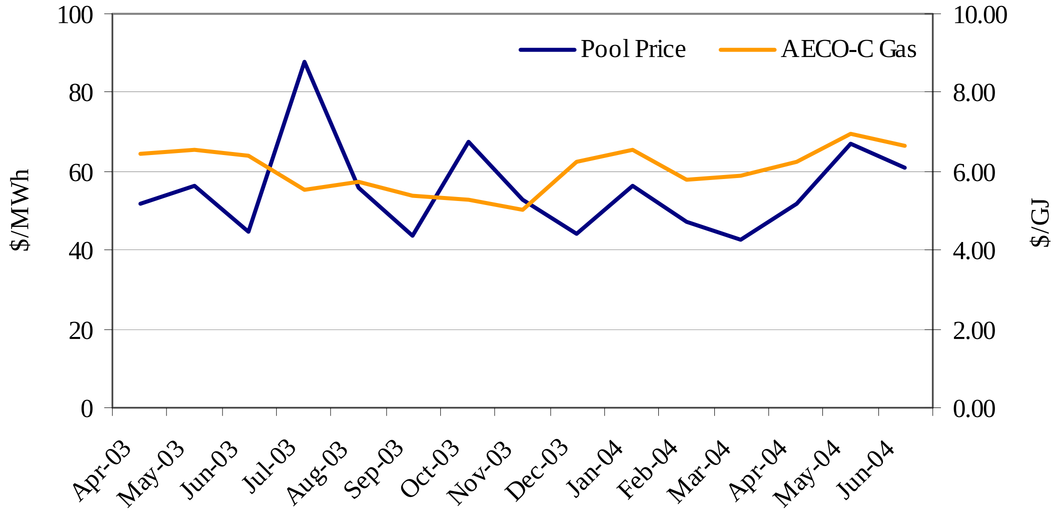


1.2 Natural Gas Prices

After remaining relatively flat through the first quarter of 2004, Alberta gas prices moved higher in Q2/04, reaching a monthly average of $6.98/GJ in May – the highest monthly average observed since early 2003. **Figure 3** shows wholesale electricity prices over the last 15 months compared to Alberta gas prices over the same period. The rolling 12 month correlation of the wholesale electricity price to gas improved marginally in Q2/04 but still remained poor due to the period of Jul – Nov

2003 when the variation in Pool price was clearly driven more strongly by factors other than the variability in gas price.

Figure 3 - Wholesale Electricity Price with AECO Gas Price



1.3 Price Setters

The concentration of marginal price setters is a metric the MSA regularly tracks as one barometer of a competitive market. **Figure 4** shows the 5 most frequent marginal price setters in Q2/04 as compared to the previous quarter, together with the weighted average price at which they set the system marginal price (SMP). It can be seen in **Figure 4** that the most frequent price setter set SMP in total, 21% of the time at a weighted average price of $70.10/MWh. This is significantly different from Q1/04 when the most active marginal price setter set SMP 25% of the time, but at a weighted average price of $28.99/MWh. This reflects that high base-load coal availability in Q1/04 resulted in coal being on the margin more frequently than gas. With the onset of maintenance season in Q2/04, and consequently lower coal availability, gas units were the marginal unit the majority of the time as reflected by the higher average SMP.

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

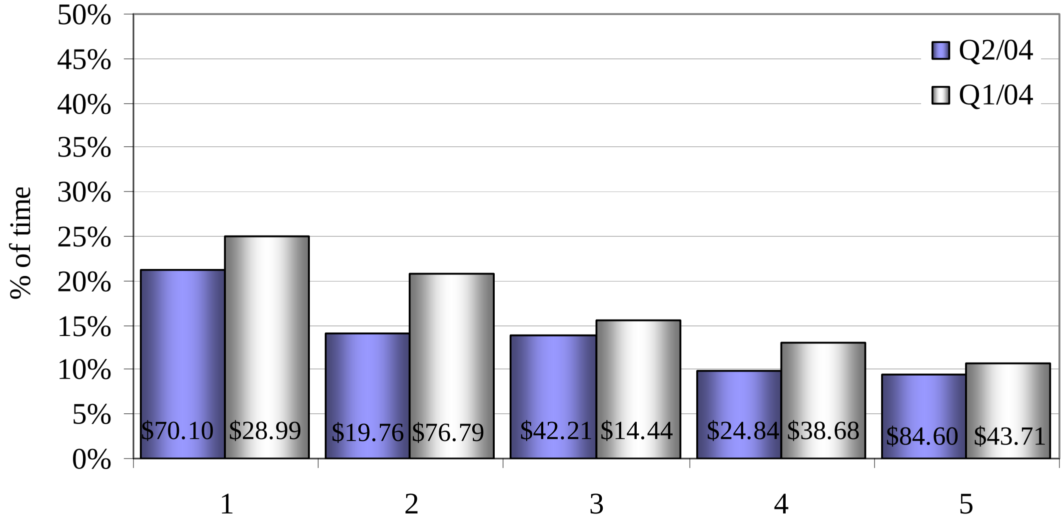
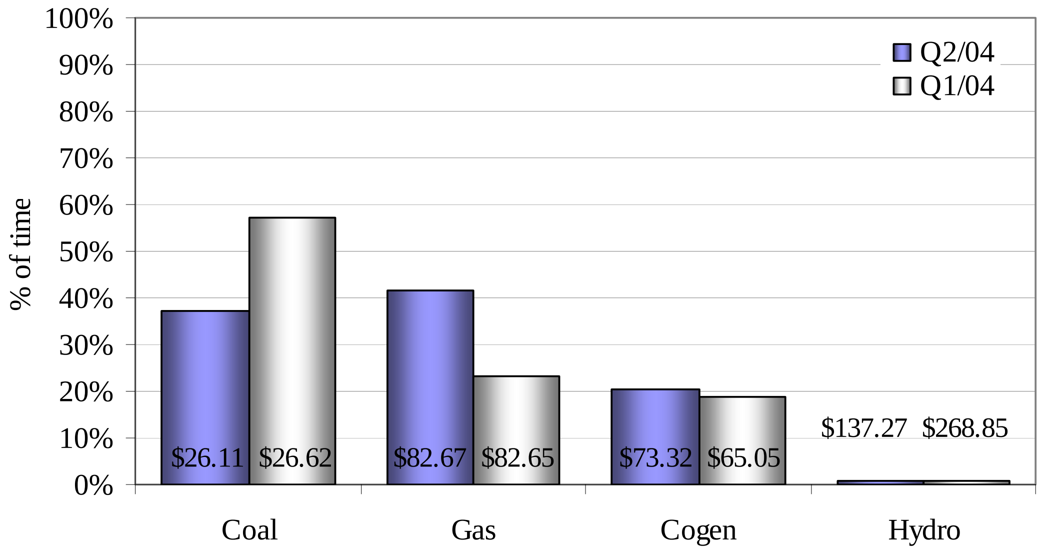


Figure 5 shows similar data although on the basis of fuel type of the marginal unit. As noted previously, the lower level of coal unit availability in Q2/04 relative to the previous quarter, resulted in a lower frequency of coal units setting SMP. Coal units set SMP for a total of 37% of the time in Q2/04 as compared to 57% of the time in Q1/04. Gas units combined (co-gen gas + other gas) set price 62% of the time in Q2/04 at an overall weighted average SMP of $79.59/MWh.

Figure 5 - Price Setters by Fuel Type



1.4 Implied Market Heat Rate

Implied market heat rate is defined as the electricity price divided by the gas price and is a metric important to gas generators since it reflects their profitability – in essence, dollars earned relative to dollars burned. Implied heat rates moved higher in Q2/04 relative to Q1/04 and Q2/03 as higher wholesale electricity prices in Q2/04 more than made up for the higher cost of buying gas. **Figure 6** shows the on and off-peak quarterly trend in implied heat rate. As noted in **Figure 6**, on-peak implied heat rate peaked in the month of May at 11.3 GJ/MWh. The duration curves in **Figure 7** show quarterly comparisons of the distribution of implied heat rates. The figure shows that a newer combined cycle gas generator could have at least met its variable operating costs about 75% of the time in Q2/04 as opposed to 50% of the time in the previous quarter. The last gas generator built in a regulated market structure would have faced equally poor prospects through the last two quarters, being in a position of recovering its variable fuel costs about 15% of the time.

Figure 6 - Implied Market Heat Rates - Q2/04

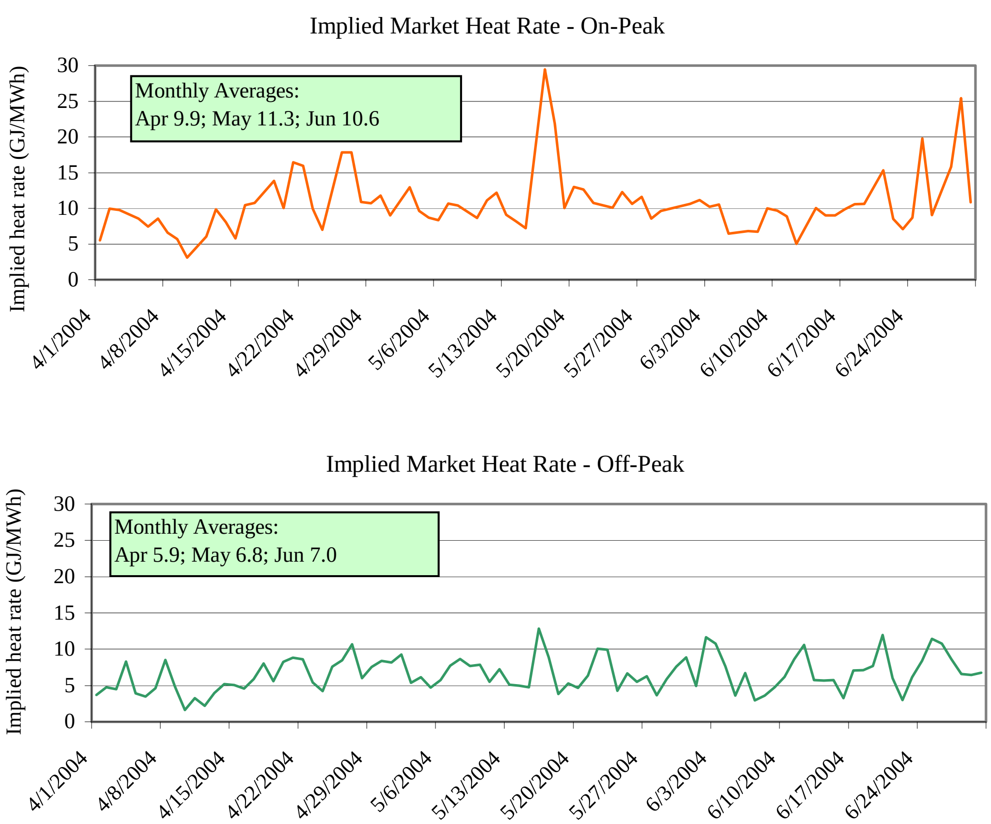
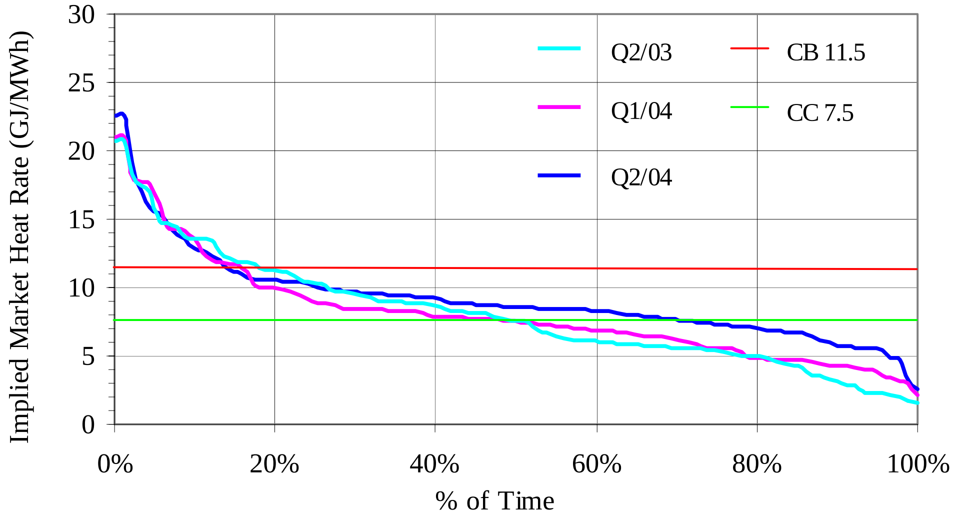


Figure 7 - Heat Rate Duration Curves (All Hours)



1.5 New AESO Rules

There were no significant changes to AESO rules in Q2/04.

1.6 New Supply and Load Growth

No significant generation was brought on line during Q2/04.

The monthly average hourly system demand for electrical energy in Q2/04 was:

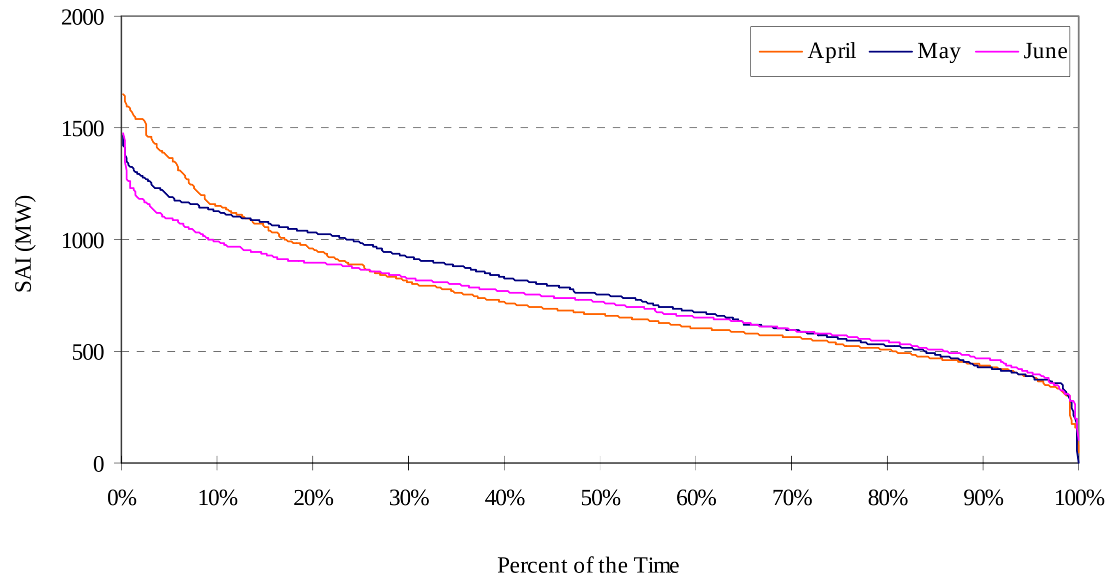
April	7055 MW	+ 1.8% vs. Apr 2003
May	7022 MW	+ 3.2% vs. May 2003
June	7223 MW	+ 7.1% vs. Jun 2003

In Q2/04 peak demand was 8495 MW which was reached in HE 16 on June 28. The wholesale price coinciding with this hour was $141.00/MWh. Peak demand increased 8.9% from the peak demand recorded in the same period a year ago. Despite this year over year increase, load factor in Q2/04 was 84% relative to 87% in Q2/03.

1.7 Supply Availability Index

SAI is a metric adopted by the MSA which approximates market "tightness" or the surplus of available supply relative to demand. This metric is defined simply as the average volume of energy remaining in the merit order above the level of dispatch over the hour. This represents the energy available to system control intra-hour since import flows are fixed prior to each hour. **Figure 8** shows duration curves of SAI for each month in Q2/04. Because the curves are closely grouped at the "tight" end of the curve where correlation to price is expected to be highest, the quarter was relatively consistent month to month in terms of the influence of supply availability. In Q2/04 the correlation between SAI and Pool price was determined as -0.54 as compared to -0.47 in Q1/04, indicating that the correlation strengthened marginally in Q2/04.

Figure 8 - SAI Monthly Duration Curves, Q2/04



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 Q2/04.

Table 2 - Tie Line Activity Q2/04

	BC			Saskatchewan			Overall		
	Imports	Exports	Net Imports	Imports	Exports	Net Imports	Imports	Exports	Net Imports
	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
April	*68,893*	*99,625*	(30,732)	*36,467*	*4,166*	32,301	105,360	103,791	1,569
May	*82,726*	*67,866*	14,860	*36,976*	*1,475*	35,501	119,702	69,341	50,361
June	*199,941*	*48,907*	151,034	*74,843*	*4,046*	70,797	274,784	52,953	221,831
Total	**351,560**	**216,398**	**135,162**	**148,286**	**9,687**	**138,599**	**499,846**	**226,085**	**273,761**
On-Peak	90%	16%		71%	66%		85%	18%	
Off-Peak	10%	84%		29%	34%		15%	82%	

Note: Negative net imports denote a net export position

In Q2/04, Alberta was an overall net importer. Import volumes were strong on both tie lines and occurred mainly in the on-peak hours. Considerable export activity was experienced on the BC tie-line (96% of the total) occurring primarily during the off-peak hours. On the BC tie-line, imports increased throughout the quarter while exports declined. On the Saskatchewan tie-line, export volumes held relatively constant while imports surged in June. Higher import levels in June were due in part to generation outages that required some participants to import energy in order to cover their short physical position. Over the course of the quarter, Alberta imported close to 500,000 MWh and exported approximately 226,000 MWh of electricity.

Figure 9 shows the relative market shares of importers and exporters in Q2/04. The figures include imports and exports on both the BC and Saskatchewan tie-lines. Both importing and exporting were dominated by one market participant (Powerex) with a 38% market share of imports (down from 52% last quarter) and a 72% market share of exports (down slightly from 74% last quarter). Relative market shares of other participants have also changed somewhat since last quarter. The second largest importer has increased its market share by 13% (up to 24% from 11% last quarter) while the third largest importer increased 16% from last quarter. The market shares for participants remained generally static on the export side.

Figure 9 - Market Share of Importers and Exporters, Q2/04

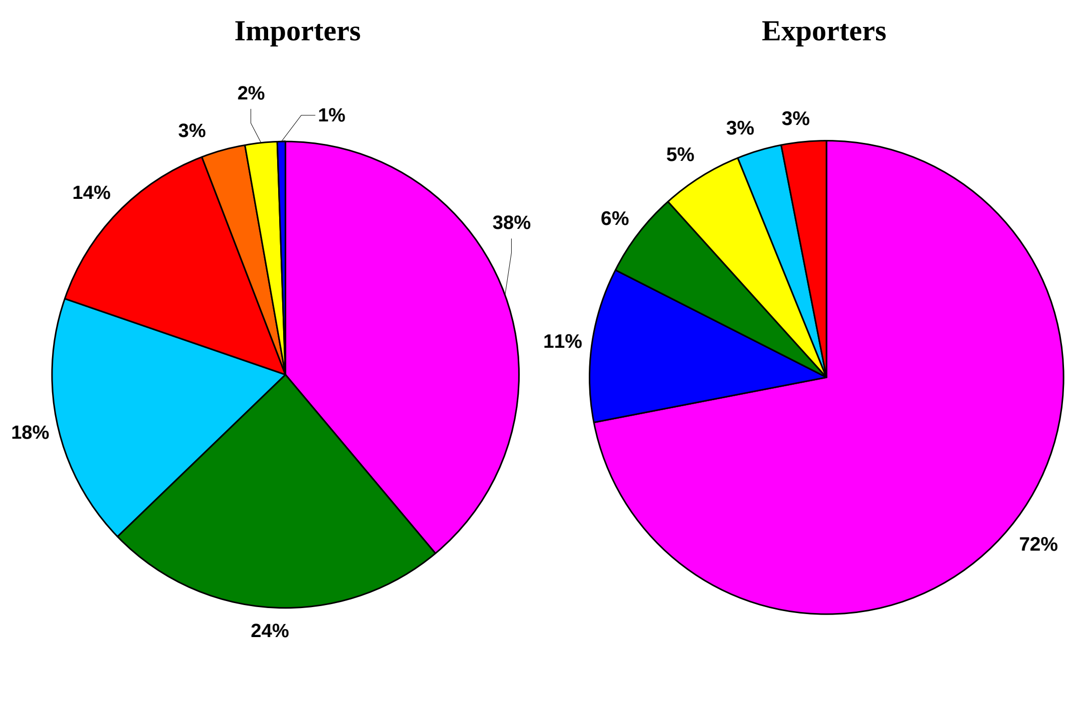
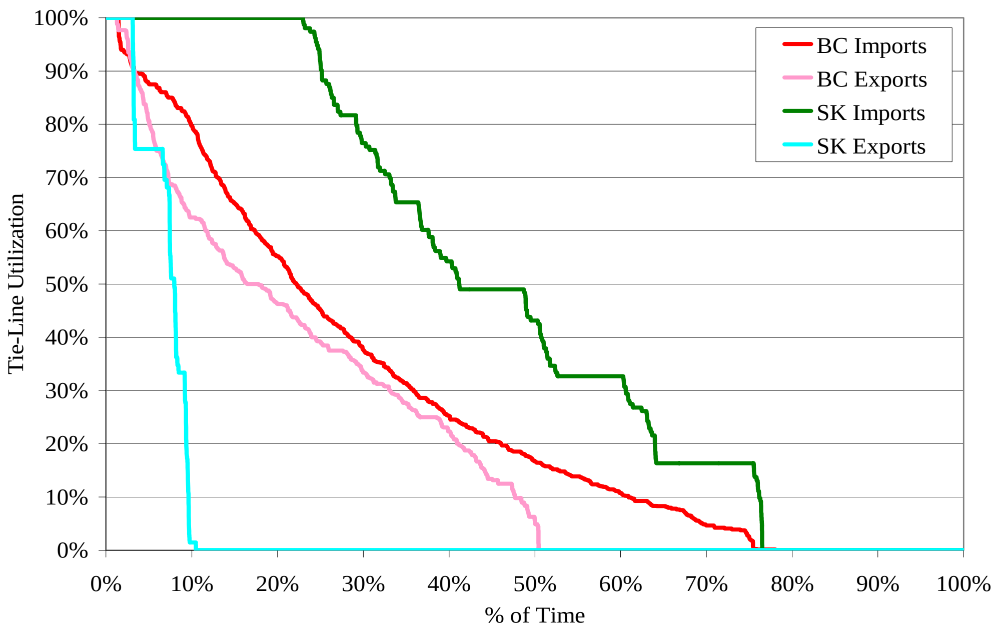


Figure 10 shows a duration curve of tie-line utilization in Q2/04 as a function of available transfer capability (ATC)[1]. The figure shows that there is unutilized capacity available on all of the tie-lines almost all of the time. The SK import ATC was the most effectively utilized in Q2/04 as there was some volume of energy being imported to Alberta from (or through) SK approximately 76% of the time that the line was available. The BC import ATC was only slightly less used at 75% utilization. The Saskatchewan export capacity was the most underutilized in Q2/04. This capacity was essentially never fully utilized and was not used at all approximately 89% of the time.

Figure 10 – Tie-Line Utilization, Q2/04



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 April 2003 through June 2004 period. During Q2/04, 85% of imports occurred during on-peak

[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.

hours and 82% 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

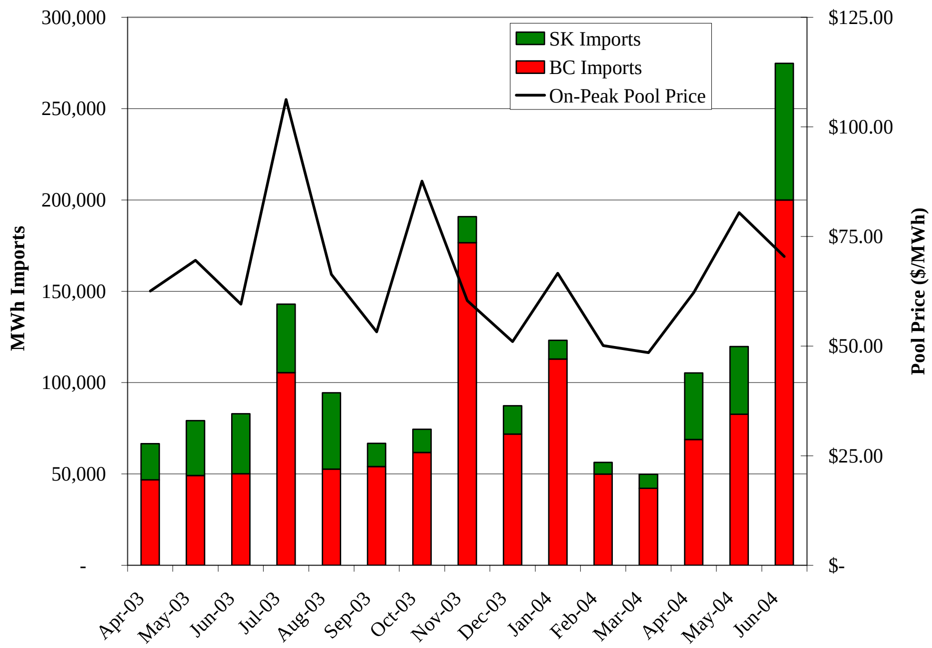
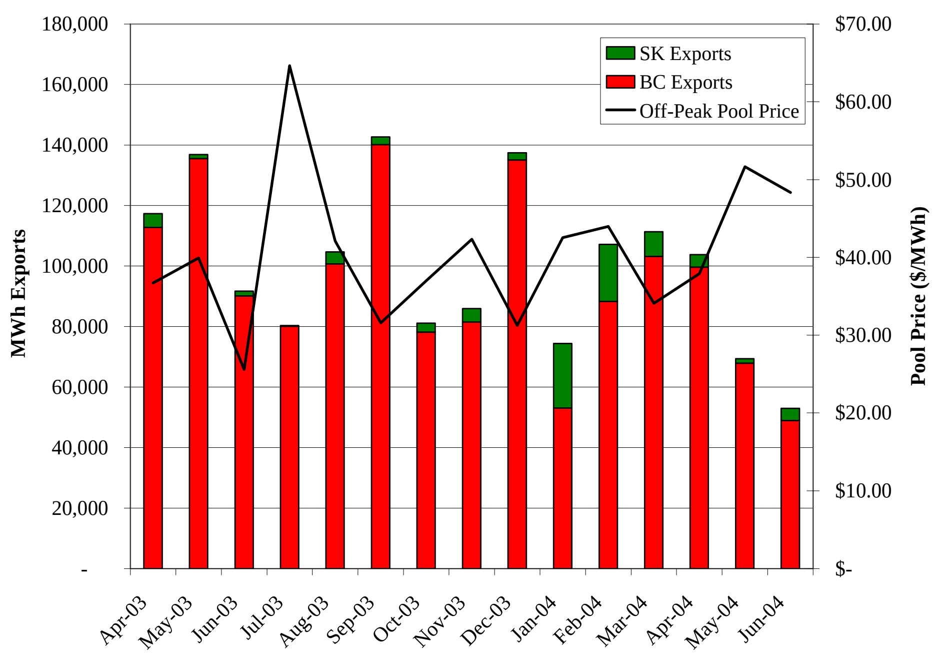


Figure 12 – Exports and Off-Peak Pool Price



During Q2/04, import volumes corresponded fairly well with on-peak Pool prices – as prices increased, the volume of imports increased. The average on-peak Pool price in Q2/04 was $71.04/MWh and a total of over 499,000 MWh of electricity were imported compared to approximately 229,000

MWh being imported at an average price of $55.08/MWh in Q1/04. Import volumes reached a 15-month high in June 2004 with just under 200,000 MWh of imports for the month.

During Q2/04 the typical inverse relationship between off-peak Pool price and export volumes was prevalent. Exports on the BC tie-line reached a 15-month low in June. This could be due to a number of factors but is likely a result of fairly modest price differentials between Alberta and Mid-C. Imports from (and through) Saskatchewan have increased dramatically this quarter over last quarter. In Q1/04 imports on the Saskatchewan tie-line totaled 24,400 MWh while in Q2/04 imports on this the-line increased over six times to 148,286 MWh.

Figure 13 - Price Paid for Imports and Exports

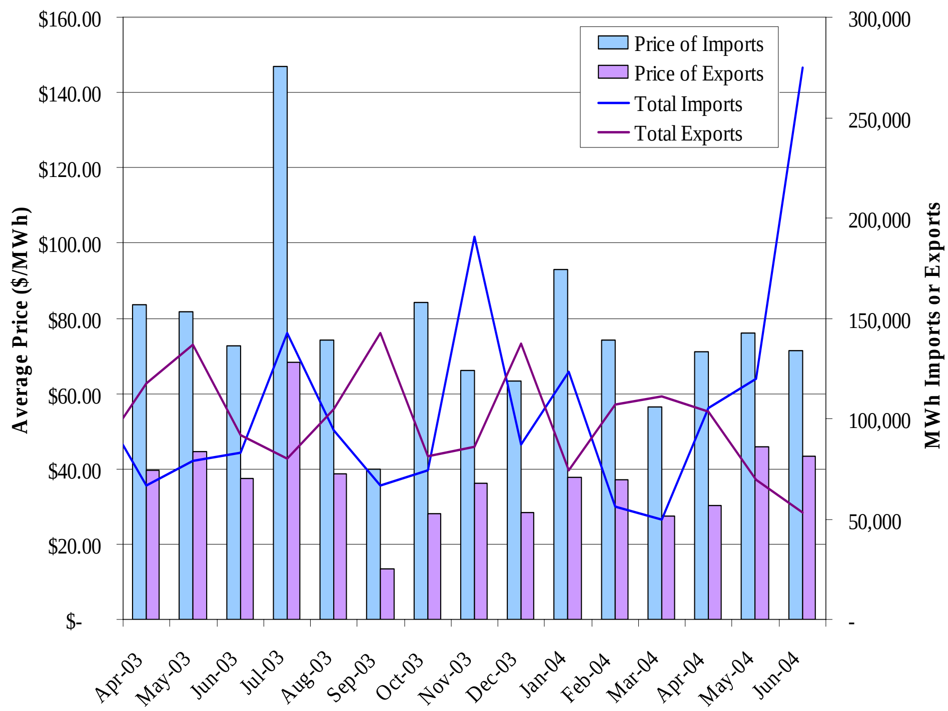


Figure 13 plots the volume-weighted monthly average price paid to importers and paid by exporters along with total monthly imports and exports for the past 15 months. For the quarter, the average price paid to importers was $72.86/MWh while the average price paid by exporters was $39.84/MWh. (These values exclude the cost of transmission and losses.) In general, the average price received for imports is directly related to the volume of imports in the month. Although the relationship is less obvious, the average price paid for exports tends to be inversely related to the volume of exports in the month. These are the types of relationships we would expect to see in a well-functioning market.

Prices in other markets have an impact on the economics 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.

Figure 14 - On-Peak Prices in Other Markets

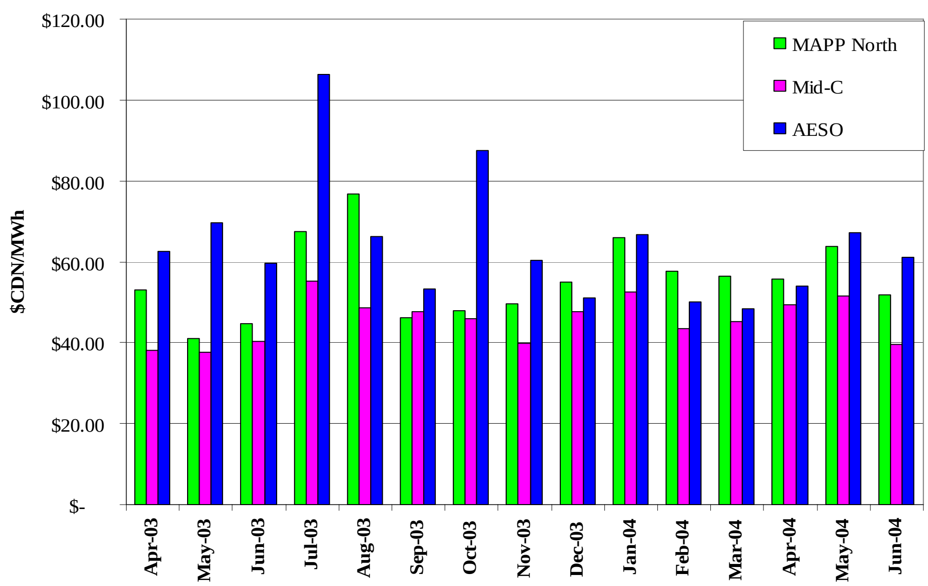
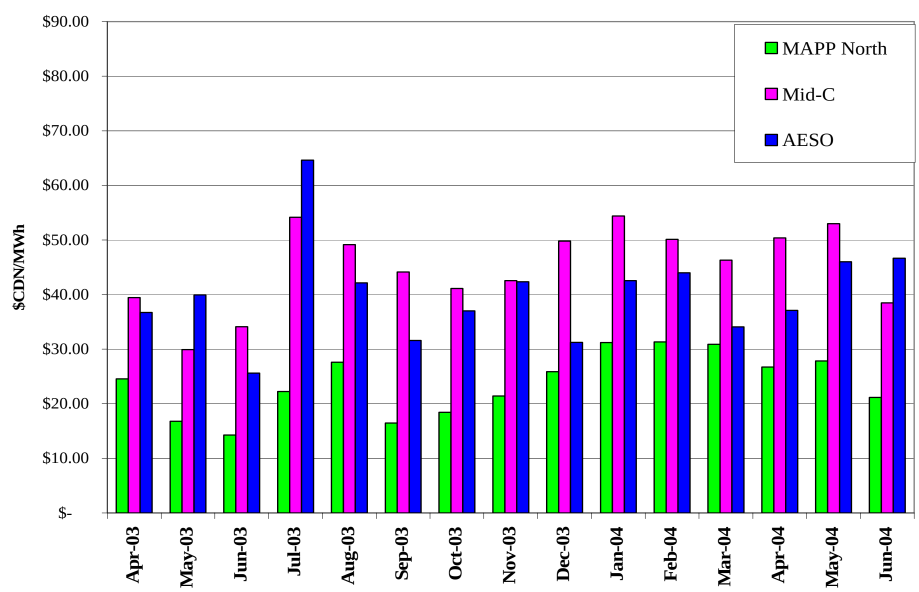


Figure 15 - Off-Peak Prices in Other Markets



On-peak Prices at MAPP-N were marginally stronger than Pool prices in April but weaker in May and June and this is reflected by reduced export volumes on the Saskatchewan tie-line in Q2/04 relative to the previous quarter. On-peak prices at Mid-C were generally lower than Pool prices –

particularly in June. This corresponds well with observed activity on the BC tie-line as 90% of imports from the west occurred in on-peak hours and most import activity was observed in June which was a 15-month peak in import volumes from BC.

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 and are reflected in the actual import/export activity observed over the last quarter.

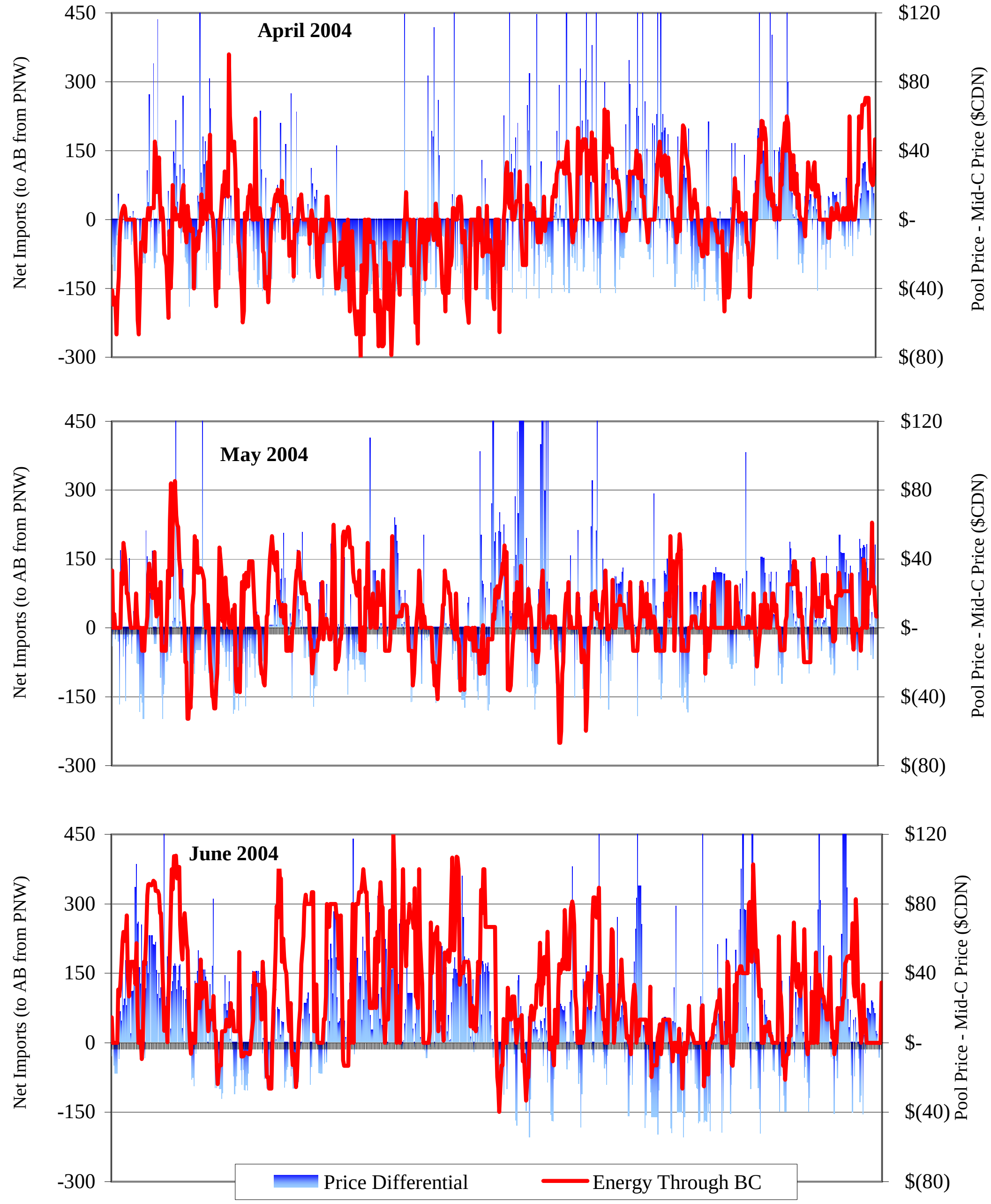
Because neither BC nor Saskatchewan operate open markets, it is difficult to assess the economics of moving energy to and from these areas. However, energy is often moved through BC and Saskatchewan to markets in the US[2]. **Figures 16 and 17** attempt to capture the economic use of the BC and Saskatchewan 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 right 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 likely not cover the cost of transmission and losses between the source and sink of the power. Moving forward, the MSA will be reviewing the usefulness of an hourly MID-C index as a tool that may provide a more accurate reflection of pricing in the Pacific Northwest when looking at economic use of the BC tie.

The use of the tie lines has been a concern among some market participants since interconnection flows, particularly with respect to BC, can have a significant effect on market outcomes. The MSA is looking closely at interconnection activity to monitor and assess whether energy flows are consistent with market fundamentals and will address any issues found as appropriate.

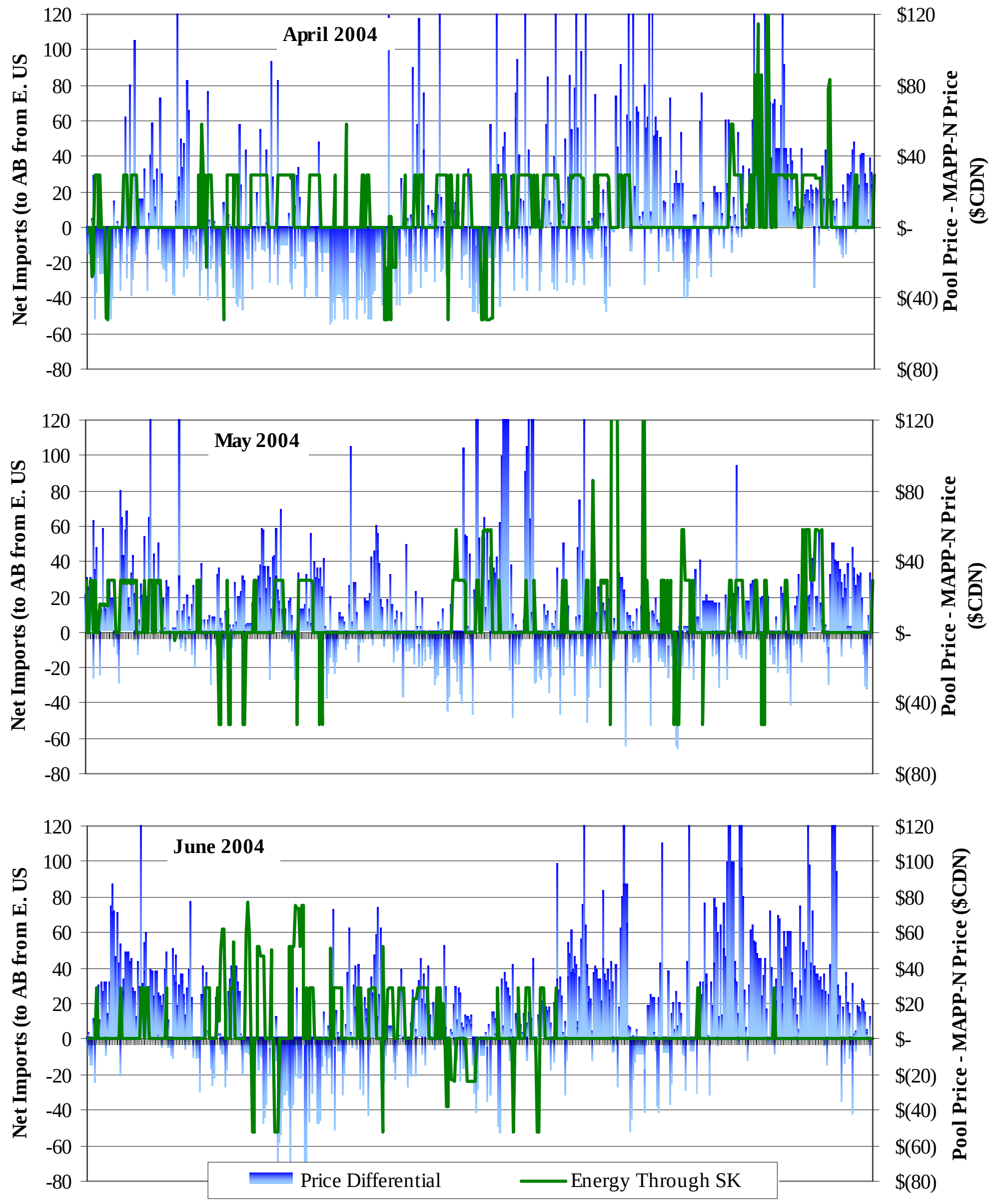
[2] The difference in the price at which energy can be bought and sold gives an indication of the economically correct direction for energy to be moving across the tie-line. For example, if the Pool price in Alberta is $50/MWh and the price at MID-C is $100/MWh, it would be most economically efficient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

Figure 16 - Economic Use of the BC 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.

Figure 17 also indicates that for the majority of the quarter, energy moving through Saskatchewan was traveling in the right economic direction. Some hours of apparent uneconomic importing occurred, however most of these imports originated from Manitoba – a regulated market.

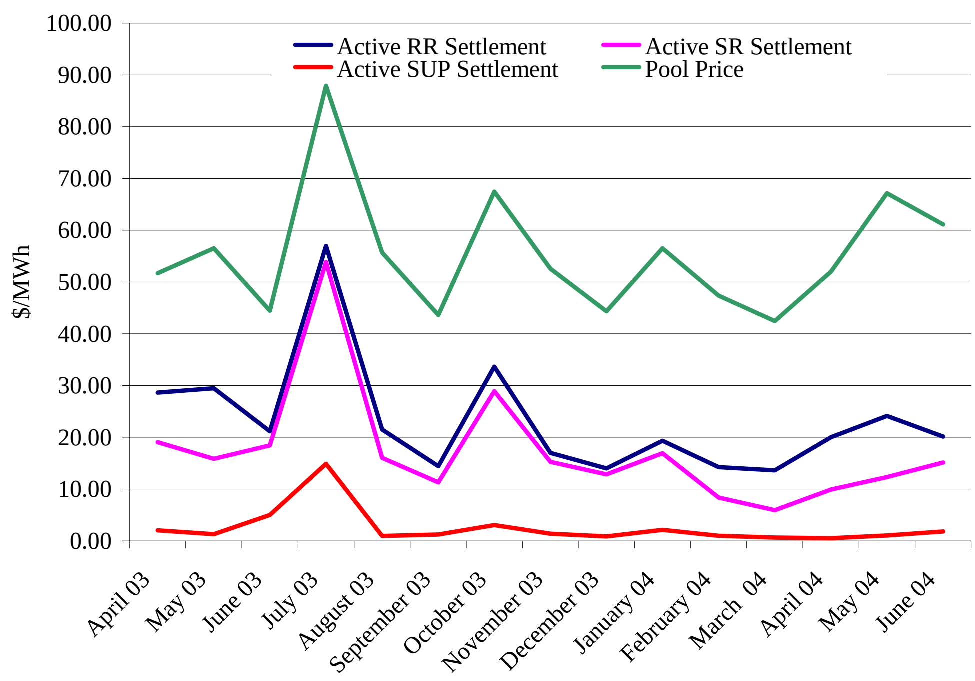
1.9 Ancillary Services Market

The AESO procures operating reserves through the Alberta Watt-Ex Market and through bilateral over-the-counter (OTC) deals with ancillary service providers. These system support services include active and standby regulating reserves, spinning reserves and supplemental reserves.

Active Prices

Figure 18 provides a 15-month overview of monthly Pool prices and settlement prices for active products including both Watt-Ex and OTC transactions. Active products are priced based on a discount from Pool price. Therefore the settlement price reflects the market clearing price that consists of the Pool price minus the discount[3]. As **Figure 18** shows, the active products have trended with Pool price, reflecting their indexation. In Q2/2004, both Pool price and active settlement prices have firmed up, as compared with the generally downward trend witnessed from July 2003 through March 2004. In Q2/04, active regulating averaged $21.43/MWh compared with $15.71/MWh in Q1/04. Spinning prices also trended up, averaging $12.46 in Q2/04 compared with $10.39/MWh in Q1/04. Average supplemental settlement prices were down slightly in Q2/04, averaging $1.13/MWh, compared with $1.26/MWh in Q1/04.

Figure 18 - Active Settlement Prices - All Markets (Watt-ex and OTC)

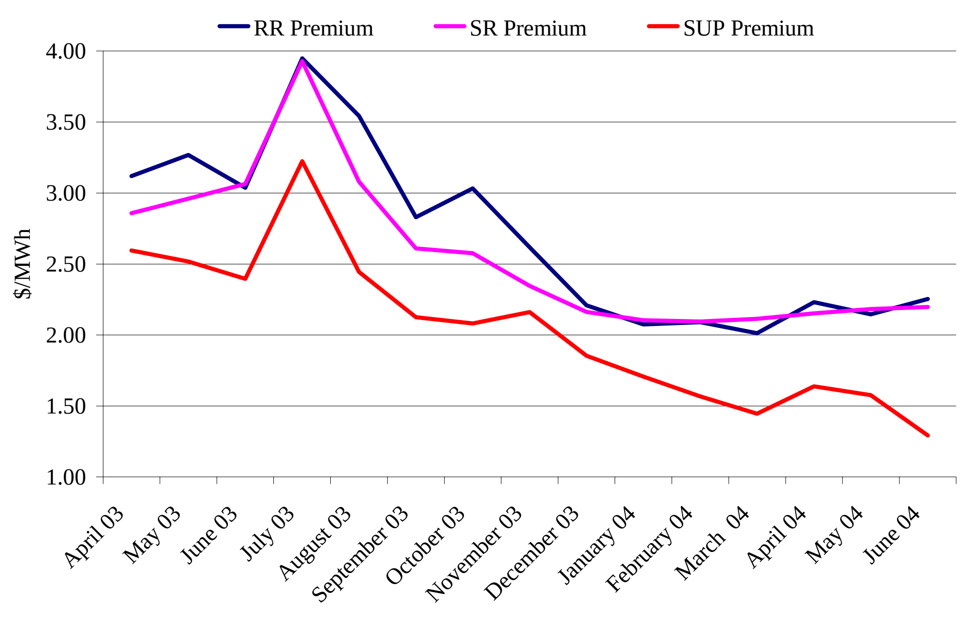


[3] A relatively small percentage of contracts are sold as fixed price contracts, which are not indexed to Pool price.

Standby Ancillary Services

Standby Services are compensated using a two part option type payment with a premium payment for availability in the standby market and a fixed activation price if the unit is called for active service. As with the active market, both the premium payments and the activation prices have trended downwards from July 2003 through March 2004. In Q2/04, premium prices have leveled out, with regulating and spinning prices showing slight growth. Supplemental premiums see an up-tick in April 2004 before continuing to trend downwards through the end of June. **Figure 19** outlines monthly average premium payments for standby regulation, spinning and supplemental reserves. Since peaking in July 2003, at monthly average premiums of $3.95/MWh, $3.93/MWh and $3.22/MWh for regulating, spinning and supplemental respectively, premium payments declined by 43%, 44% and 60% through the end of June. In Q2/04 premiums averaged $2.21/MWh, $2.18/MWh and $1.50/MWh compared with $2.06/MWh, $2.10/MWh and $1.57/MWh in Q1/04 for regulating, spinning and supplemental, respectively.

Figure 19 - Standby Premiums - All Markets (Watt-Ex and OTC)

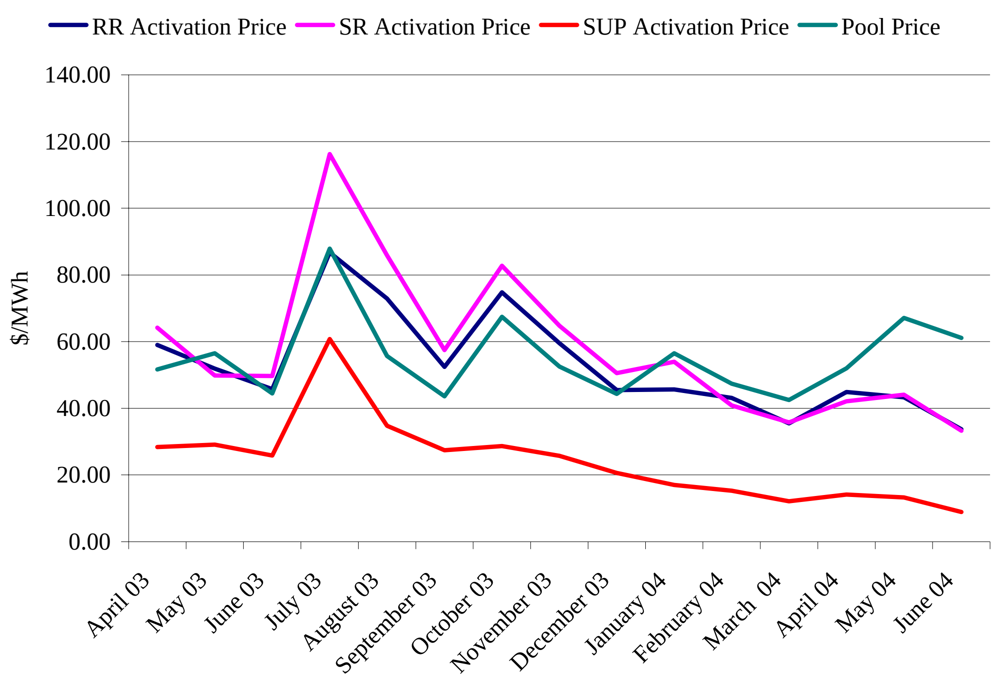


Standby activation prices have also trended down (**Figure 20**). Since peaking in July 2003, average standby activation prices have declined by 61%, 71% and 85% for regulating, spinning and supplemental reserves compared with March 2004. After rebounding somewhat in April, standby activation prices continued to decline although at a slower rate than the July 2003 through March 2004 period. Standby activation prices averaged $40.64/MWh, $39.85/MWh and $12.09/MWh for standby regulating, spinning and supplemental in Q2/04 compared to $41.43/MWh, $43.53/MWh and 14.81/MWh in Q1/04. Note that these prices include all standby contracts purchased by the AESO, regardless of whether they were activated.

For regulating and spinning, prices appear to have stabilized after relatively rapid declines from July 2003 to March 2004. This is likely due, in part to stabilization in Pool price, which generally trended up in Q2/04. The reduced decline in standby prices may also be a sign of a more matured market that has seen fewer new players in the first half of 2004 compared to the first half of 2003.

It is also interesting to note that there has been a general pattern of convergence between standby regulating and standby spinning prices, in terms of both the premiums and fixed activation prices. Regulating is generally viewed as a higher value product given that a provider is paid the premium, fixed activation price and Pool price for any energy produced if activated, rather than receiving the premium and activation price as with spinning activation. However, the probability of getting activated is higher for spinning than regulating (see **Figure 21** for activation rates).

Figure 20 - Standby Activation Price - All Markets (Watt-Ex and OTC)

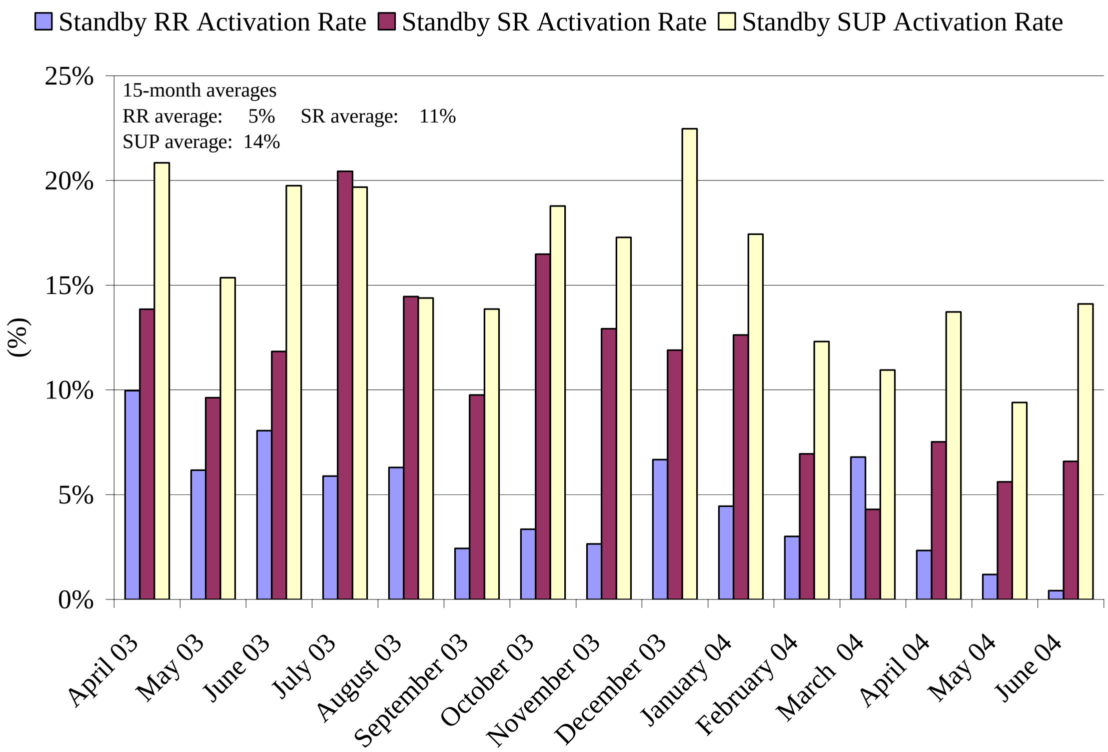


Note: Activation prices are reported for all standby contracts, regardless of whether the contract capacity was activated.

Activation Rates

Activation rates in the standby market have shown some variability over time (**Figure 21**). Variability is expected because standby activations occur due to (random) mechanical failures at units providing active reserves or due to forecast error. Over the past 15 months, activation rates for standby regulating, spinning and supplemental reserves have averaged 5%, 11% and 16% respectively. In Q2/04, activation rates were 1.3%, 7% and 12% for standby regulating, spinning and supplemental respectively, well below the 15-month averages. These figures compare with 5%, 8% and 14% in Q1/04. This decline in activation rates year to date can be partially attributed to the participation of newer assets in the ancillary services market that are less subject to forced outage while providing active reserve services.

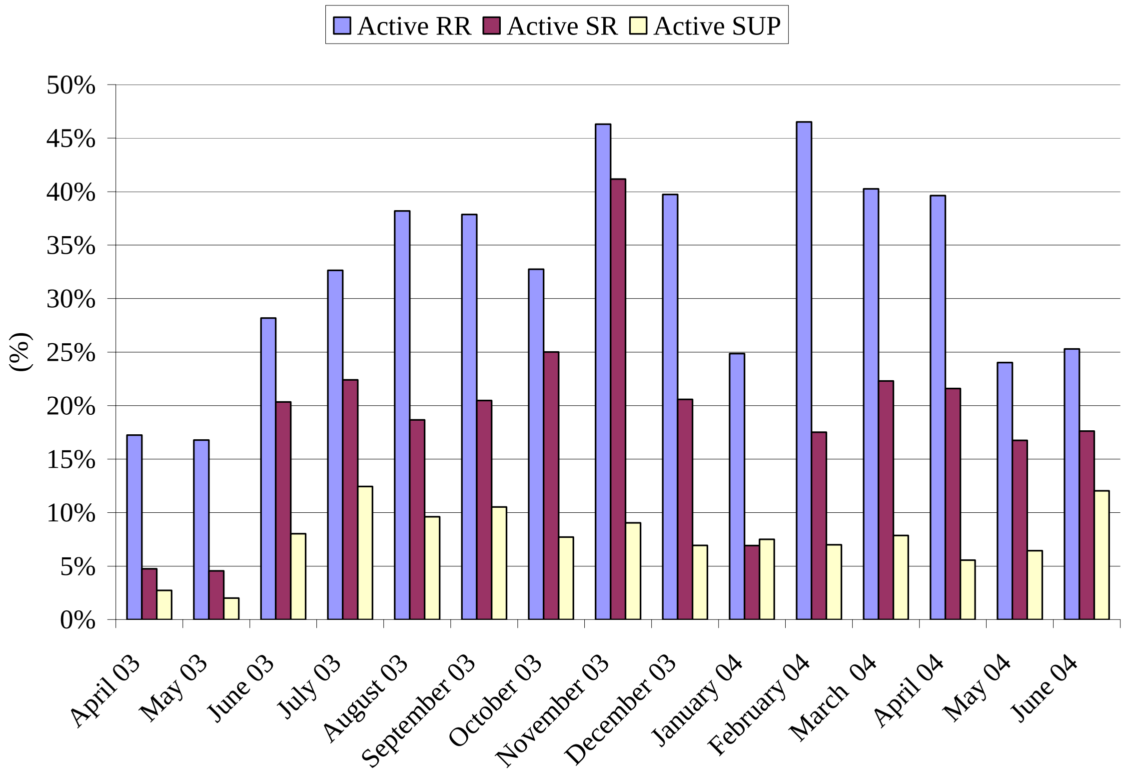
Figure 21 - Standby Activation Rates



OTC Procurement

Since June of 2003, there has been a shift in the AESO's procurement strategy, with more volumes being procured through bi-lateral OTC deals rather than standard Watt-Ex products. **Figure 22** shows the percentage of OTC procured volumes over the last 15 months. In Q1/04, 37% of regulating reserve was procured OTC, 15.6% of spinning and 7.4% of supplemental. Active regulating procured OTC declined to a 12-month low of 22.7% in May 2004, while averaging 27.6% for the quarter. OTC procured spinning reserve was relatively steady month to month in Q2/04 and averaged 18% for the quarter. Supplemental OTC procurement was up slightly for the quarter, averaging 8% for the 3-month period and peaking at 12% in June.

Figure 22 - OTC Procurement as a Percent of Total Procurement



Fixed Price OTC Products

Since December 2003, the AESO has purchased some active regulating and spinning volumes as fixed price rather than indexed to Pool price. Fixed price contracts act to limit exposure to Pool price volatility for the purchaser and lock in revenues for the seller. In most months, the volume of fixed price contracts is relatively low, remaining under 5% of purchased volumes by product (**Figure 23)**. The exception to this was February 2004, where 25% of active regulating reserves were purchased using fixed price instruments.

Fixed price contract prices are reported in **Figure 24**. Fixed price regulating has been relatively stable, ranging from $13/MWh to $15.50/MWh between January and June, 2004. Fixed prices for spinning reserve have ranged between $10/MWh and $20/MWh.

Figure 23 - % of Active Regulating and Spinning Purchased as Fixed Price

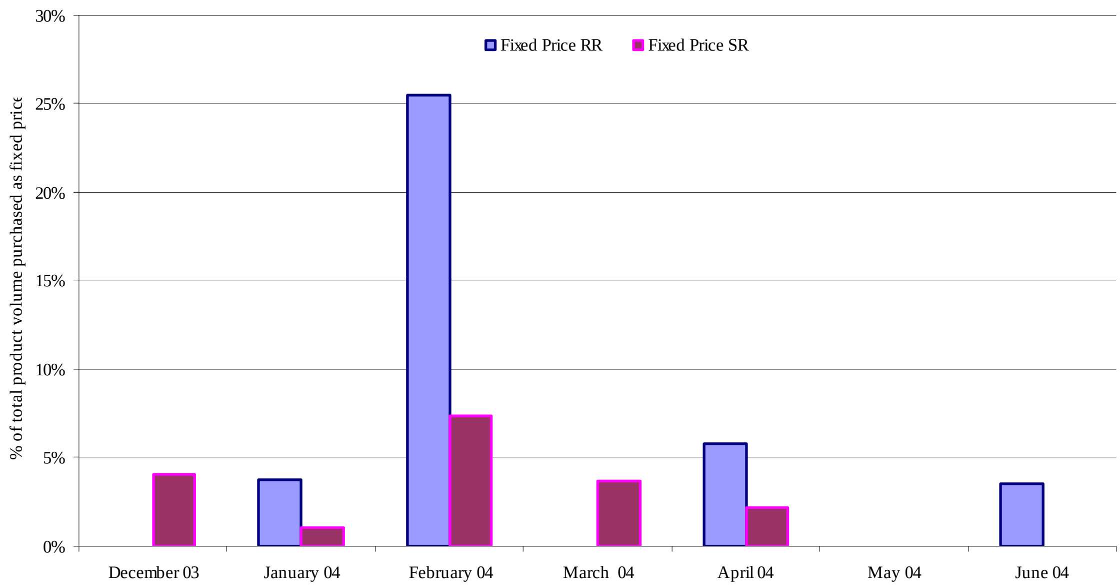
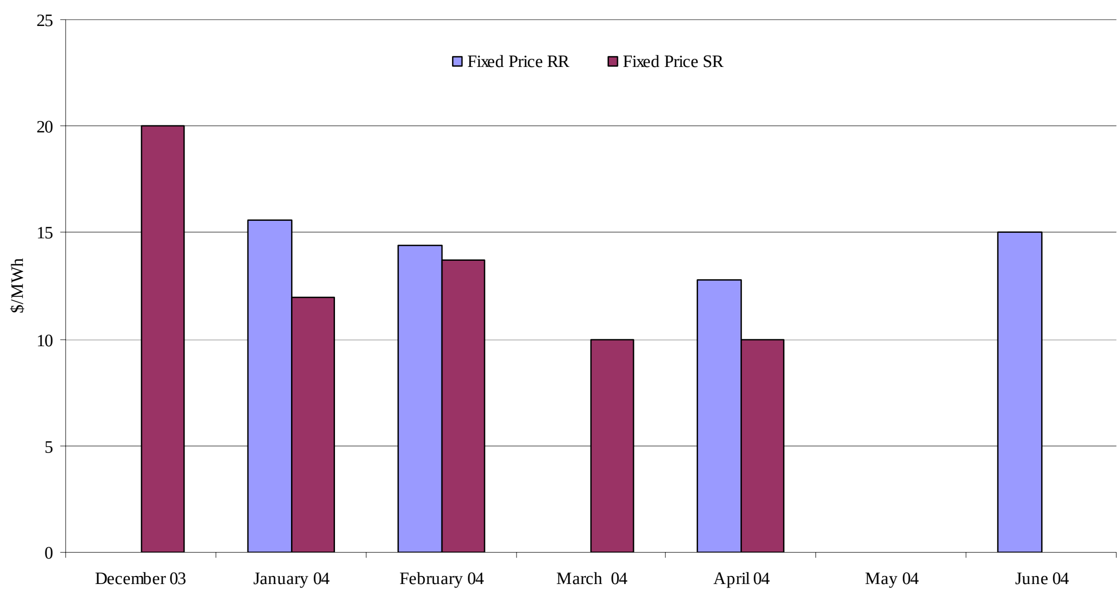


Figure 24 - Active Regulating and Spinning Fixed Prices



Figures 25, 26 and 27 report Watt-Ex, OTC and overall MW weighted average prices (all markets) for active regulating, spinning and supplemental. In general, OTC procured volumes for regulating and spinning are priced, on average, slightly higher than Watt-Ex purchased volumes. The price differential may be due in part to the AESO's requirement to purchase custom products, such as shaping contracts in the OTC market. The Watt-ex exchange does not trade these custom products.

Rather it focuses on standard on-peak, off-peak and flat products. As for the supplemental market, the larger price differential is a consequence of the Hydro PPA.

Figure 25 - Active Regulating Reserve Settlement by Market

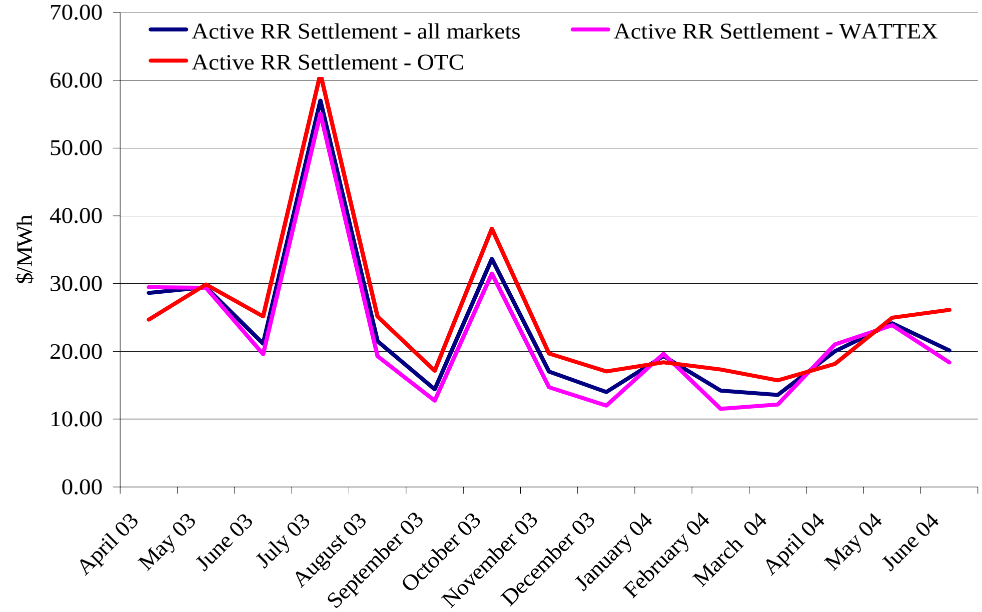


Figure 26 - Active Spinning Reserve Settlement Price by Market

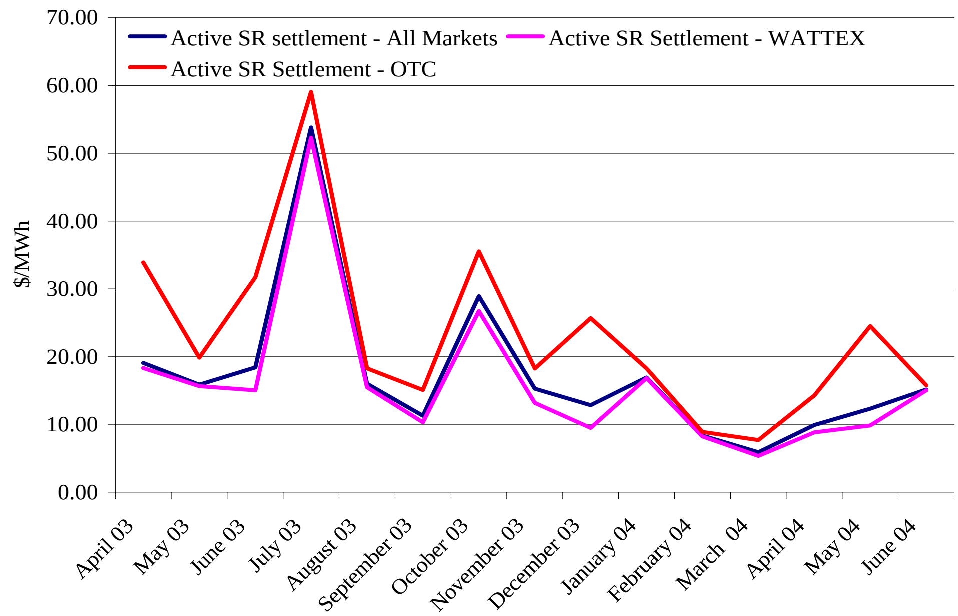
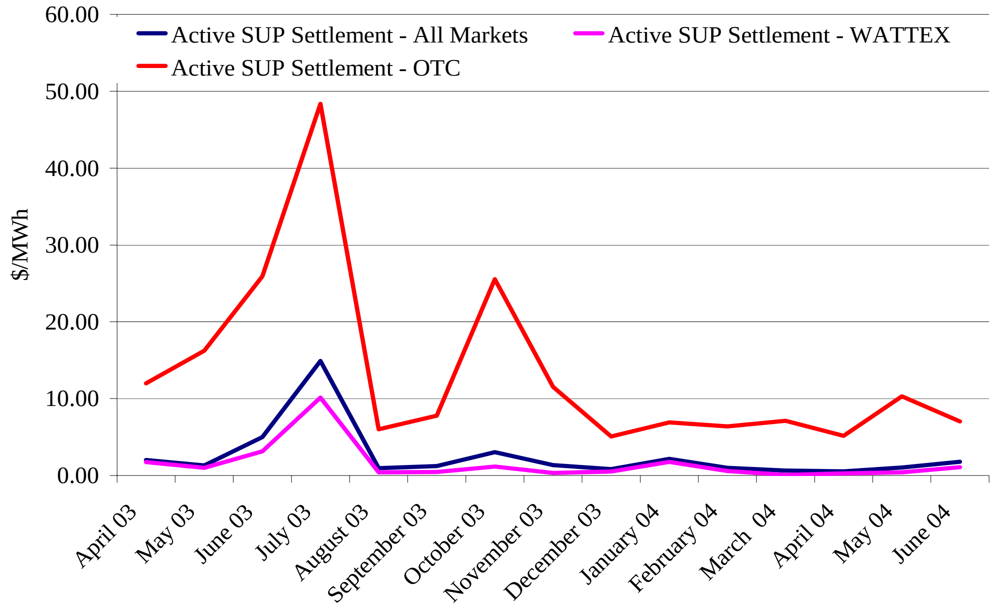


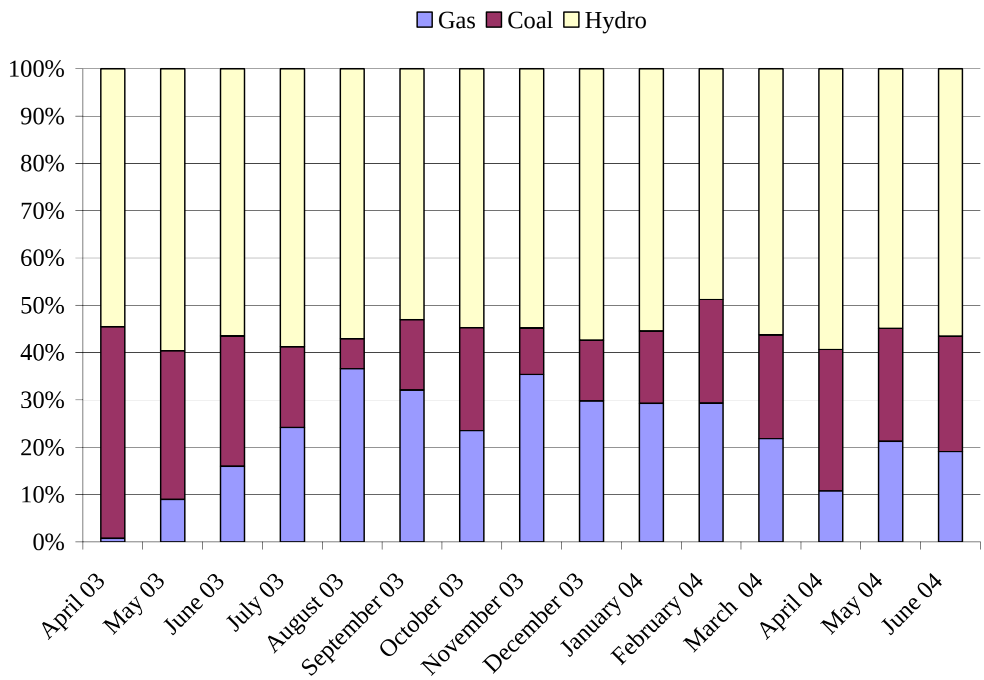
Figure 27 - Active Supplemental Reserve Settlement Price by Market



Market Share

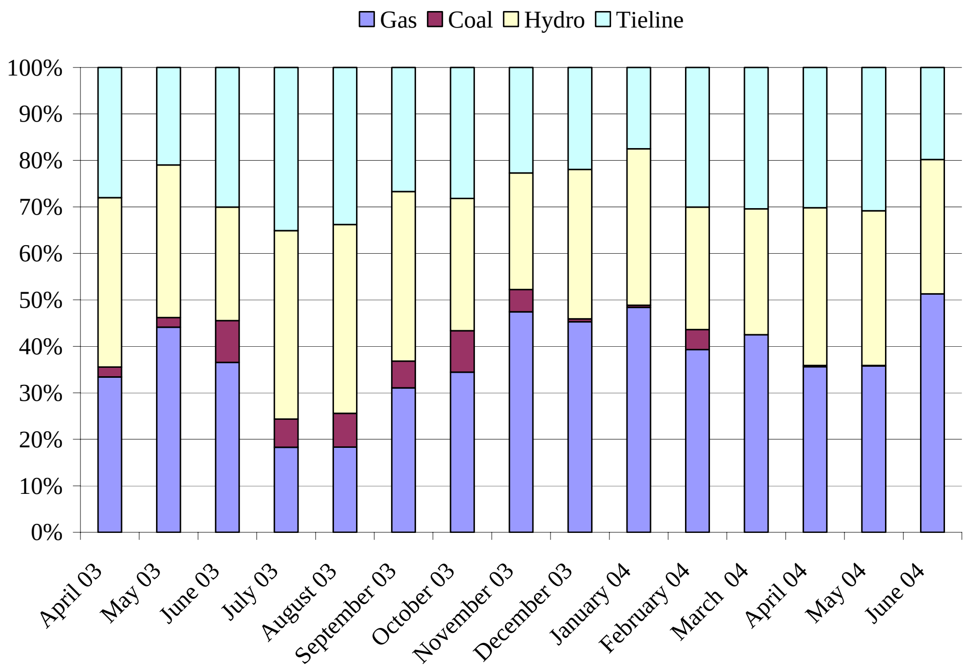
Figures 28, 29 and 30 provide market shares by type (coal, gas, hydro, load and tie-line imports) for active regulating, spinning and supplemental reserves. Regulating market share has seen some variability over the last 15 months, due to several gas-fired units entering the market in the first half of 2003. Hydro has maintained a relatively stable market share, ranging from 50%-60% of the market. One might expect a fairly stable market share from the hydro units given the obligations set out by the Hydro PPA. Gas-fired units made inroads into the active regulating market during 2003. In Q2/04, the coal facilities have regained some of this market share, averaging 26% of the market compared to 20% in Q1/04. The gas units have seen their market share fall somewhat, from 26% in Q1/04 to 17% in Q2/04.

Figure 28 - Regulating Reserve Market Share by Fuel Type



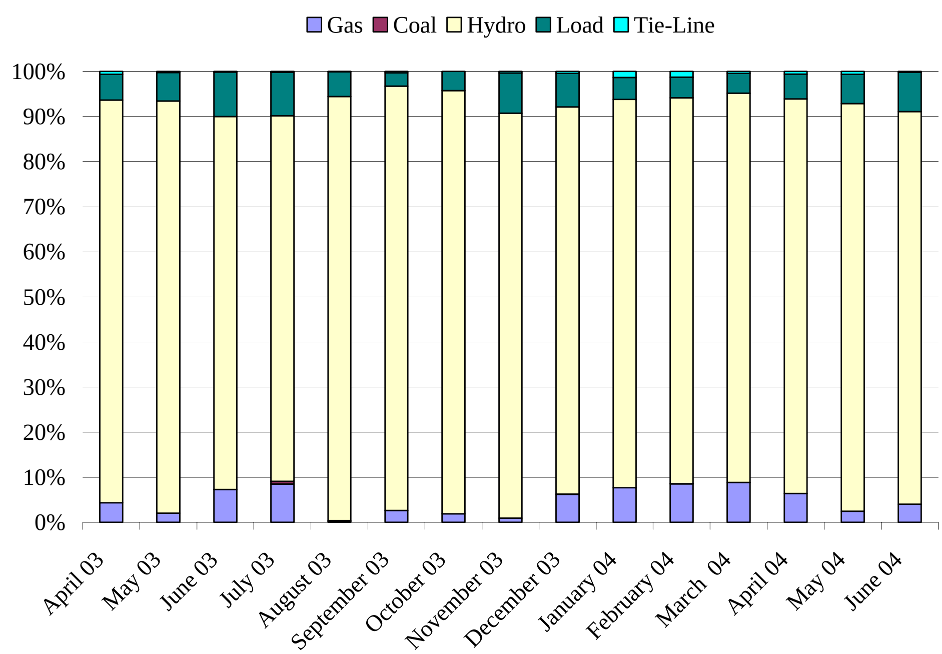
After having made some gains in the spinning market in the last half of 2003, gas-fired generation market share has stabilized in 2004. In Q1/04, gas-fired units accounted for 43% of the market. In Q2/04, the gas-fired market share declined slightly to 41%, although they accounted for over 50% of the market in June. (**Figure 29**). Hydro's market share has increased slightly from Q1/04 to Q2/04. In Q1/04, hydro accounted for 29% of the active spinning market. In Q2/04 this increased to 32%. Active spinning reserves supplied over the tie-line have remained stable, increasing from 26% to 27% of the market from Q1/04 to Q2/04.

Figure 29 - Spinning Reserve Market Share by Fuel Type



The supplemental market is dominated by hydro. In Q2/04, hydro has held 88.3% of the market with the remainder coming from load (6.9%), gas units (4.3%), imported supplemental (0.45%). Supplemental market share is driven by the effects of the Hydro PPA and large notional quantities of supplemental that the hydro units are obliged to provide.

Figure 30 - Supplemental Reserve Market Share by Fuel Type



Summary

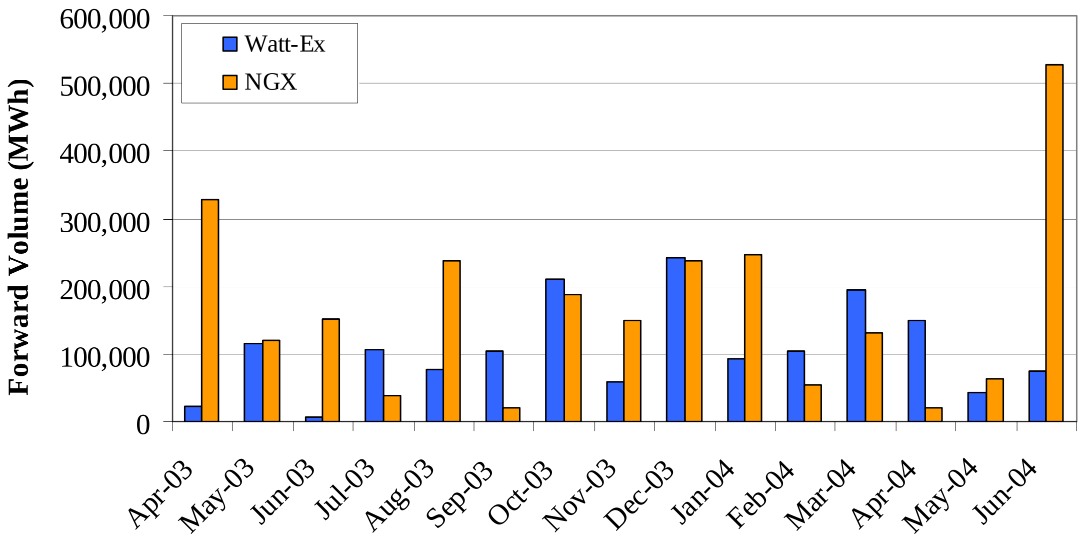
The AS market has become increasingly competitive over time, reflecting growth in available capacity and generally low heat rates and prices in the energy market. In Q2/04, the market appears to have stabilized somewhat, compared to the overall declining prices seen from July 2003 through the end of March 2004. Overall active regulating reserve prices increased 30% quarter-over-quarter. Overall active spinning reserve prices increased 20% quarter-over-quarter. The rebound in active regulating and spinning prices are likely due to the 23% increase in Pool price from Q1/04 ($48.78/MWh) to Q2/04 ($60.07/MWh), along with less new entry competition that characterized theses markets in 2003.

On a quarter-over-quarter basis, standby prices posted less impressive results. Standby regulating premiums increased 7%, while standby spinning premiums increase 4%. Supplemental premium prices declined 4%. Activation prices were down across the board, with regulating activation prices falling by 2%, spinning activation prices declining 8% and supplemental falling 18%. These results suggest the market remains extremely competitive for standby reserves.

1.10 Forward Markets

Exchange traded forward energy volumes (defined here as Watt-Ex + NGX) were up 7% in Q2/04 over traded volumes in Q1/04. **Figure 31** shows that this was due to a strong month of June for NGX trade volumes and this was attributed in large measure to two calendar year 2005 trades occurring early in the month which accounted for 48% of total forward energy deal volume in June for NGX. Watt-Ex volumes were down 31% in Q2/04 relative to the previous quarter but up substantially from volumes in the same quarter a year ago. Although **Figure 31** indicates that Watt-Ex volumes have exceeded NGX volumes in selected months, on a quarterly basis, NGX volumes have been higher relative to Watt-Ex in each of the previous five quarters, and this continues to be a function of higher frequency of trading in longer term contracts i.e.: month, quarter, calendar year, on NGX.

Figure 31 - 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.

Figure 32 illustrates the total outage levels at the coal fired generation facilities and is separated by PPA owner. The graph indicates that the outage levels for the second quarter of 2004 are up from the levels of the same quarter a year ago as a result of particularly higher outage levels for Owner A. Unplanned outages for Owner A accounted for nearly one third of the outages in Q2/04 with planned outages make up the balance. 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 Owner A, it was observed that major turnaround maintenance on certain units has not been performed in recent years. With this in mind it is not 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 32 – Outage Rates by Owner

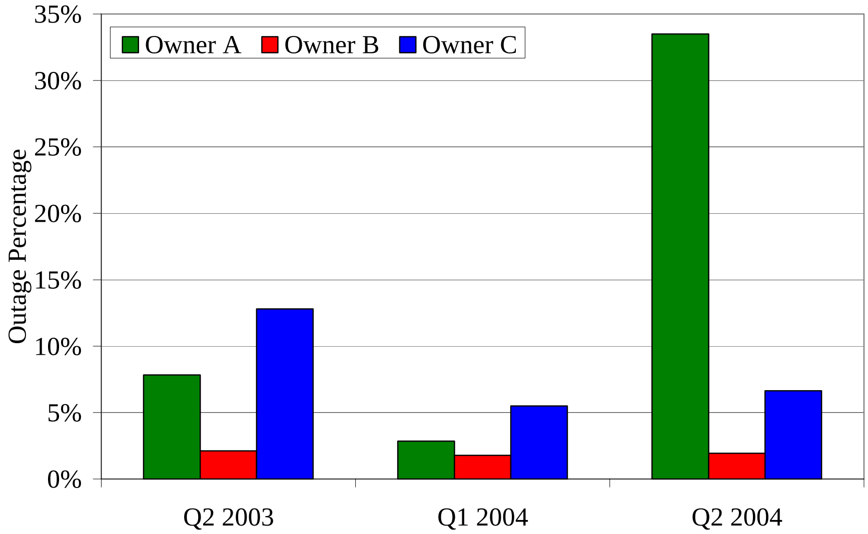


Table 3 reports the unplanned outages on a quarterly basis for the second quarter of 2004 and the previous quarter. It also shows the annual unplanned outages for comparison. Overall, Q2/04 unplanned outages are above Q1/04 and higher than the annual outages for 2003 and 2001.

Table 3 - Outage for PPA Coal Units (excluding planned outages)

	Q2/04	Q1/04	2003	2002	2001
Owner-A	**11.7%**	2.8%	4.9%	4.2%	3.2%
Owner-B	**2.1%**	1.8%	1.5%	0.5%	1.2%
Owner-C	**5.4%**	5.5%	5.7%	10.8%	8.8%
PPA weighted average	**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. **Table 4** reports the MW weighted average target availability by Owner for each coal fired portfolio and the actual availability achieved during 2002 and 2003 along with the present quarter, Q2 2004. The PPA owners have consistently reported higher actual availability relative to target availability.

The overall availability of the PPA coal units has been very close to the target for the quarter. The significant drop in availability due to Owner A outages significantly impacted the overall availability despite the other owners being above their availability targets.

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

	Target Availability 2002	Actual Availability 2002	Target Availability 2003	Actual Availability 2003	Target Availability Q2 2004	Actual Availability Q2 2004
Owner-A	88%	92%	87%	92%	87%	67%
Owner-B	90%	97%	90%	94%	90%	98%
Owner-C	85%	87%	85%	88%	87%	93%
PPA weighted Average	87%	90%	87%	90%	87%	86%

2 REVIEW OF THE RETAIL MARKET

2.1 Code of Conduct

Compliance Plans

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.

Final Approvals

Final compliance plan approvals were granted to the following parties in February, 2004: Battle River REA Ltd., Battle River Rural *Energy* Limited, Direct Energy Marketing Limited (in respect of Direct Energy Regulated Services), and Direct Energy Partnership.

Interim Approvals

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 a February 29, 2004 expiry date and the requirement for additional reporting.

By request, the interim approvals granted to those parties were further extended to June 1, 2004, to facilitate continued work on the compliance plans and other matters.

None of the parties operating under interim approval was able to obtain final approval of their compliance plan by June 1. All parties requested a further extension to the expiry date; however, under the circumstances, the MSA did not consider it appropriate to extend the interim approvals past that date. Thus, after June 1 all of the parties operating on interim approval became non-compliant with the Code requirement to have an approved compliance plan in place.

Ultimately, all of those parties were subsequently able to obtain final approval for their respective compliance plans during the month of June.

ENMAX Energy Corporation and ENMAX Power Corporation were granted final compliance plan approval effective June 25, 2004.

FortisAlberta Inc. (Aquila Networks Canada (Alberta) Ltd.) was granted final compliance plan approval effective June 30, 2004.

EPCOR Distribution Inc., EPCOR Energy Services Inc., EPCOR Energy Services (Alberta) Inc. and EPCOR Merchant and Capital L.P. were granted final compliance plan approval effective June 30, 2004.

The parties are expected to address their non-compliance in their quarterly and annual compliance reporting. This is in addition to the reporting provided as a condition of each interim approval.

Further, the MSA will be undertaking an audit type review of the operations and conduct of each of those parties, both in respect of the period between expiry of the interim approval and the granting of final approval, and the period during which their interim approval was operative. This 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 will complement the regular audit requirements of the parties for a part of the 2004 calendar year.

Application for Exemption – 2004 – 00103- Direct Energy Marketing Limited

By letter dated April 12, 2004, Direct Energy Marketing Limited (DEML) requested relief pursuant to section 43 of the Code. This request was assigned Application # 2004 – 00103.

The Application sought to address certain Code related implications which could arise depending upon how the regulated rate tariff functions of various third parties were handled by DEML. The Application was denied by the MSA on various grounds.

A copy of Notice of Application and Decision 2004 – 00103 can be found on the MSA website under Notices and Decisions.

Application for Exemption – 2004 - 00104 - ATCO Electric Ltd.

In a letter dated April 14, 2004, ATCO Electric Ltd. (ATCO) requested relief pursuant to section 43 of the Code. Specifically, ATCO sought an extension to the date by which Direct Energy Marketing Limited (DEML) was required to return certain customer information to ATCO. This request was assigned Application # 2004 – 00104.

The customer information was initially provided to DEML pursuant to MSA Decision 2003 – 00101; an extension to certain conditions in that Decision was then granted in MSA Decision 2004 - 00102. Copies of those Decisions can be found on the MSA website under Notices and Decisions.

The customer information was made available to DEML through the exemptions granted in order to facilitate system testing and other matters in advance of the anticipated sale of the ATCO retail electricity business.

Based upon communications between the MSA, ATCO and DEML in relation to the Application, it was determined that an alternate request for exemption would be better suited to the circumstances facing ATCO and DEML. In particular, timeliness was an issue.

By letter dated April 22, 2004, ATCO commenced an alternate course of action, with a revised request for relief. This request was designated by the MSA as Revised Application 2004 – 00104.

On April 23, 2004, the MSA granted the exemption sought in the Revised Application, and published its Decision within the Notice of Application and Decision 2004 – 00104. This document can be found on the MSA website under Notices and Decisions.

Default Supply Issue

At the end of 2003, the MSA was informed by ENMAX Energy Corporation (ENMAX) that it had been using default supply customer information for sales and marketing purposes, believing this to be acceptable under the Code. The MSA immediately advised ENMAX of its view that this was, in fact, not acceptable.

ENMAX offered to mitigate any harm caused by the misuse of the customer information, and proposed to offer the affected customers the right to cancel their contracts. In order to assess the proposed remedy, and the extent of the underlying harm, the MSA requested detailed information from ENMAX surrounding the matters. Under the circumstances, the information requests were not treated as an investigation, although the MSA reserved its prerogative to take that step if required.

In April, 2004 the MSA completed its assessment of the matters. The MSA concluded that the measures suggested by ENMAX, along with some added conditions, would be sufficient to address the circumstances at issue.

In May, 2004, the MSA issued a notice in respect of these matters, including as to the remedial measures agreed to. A copy of the notice can be found at: http://www.albertamsa.ca/files/NoticeUseofDefaultSupplyCustomerInfoENMAX.pdf .

2.2 Retail Market Metrics

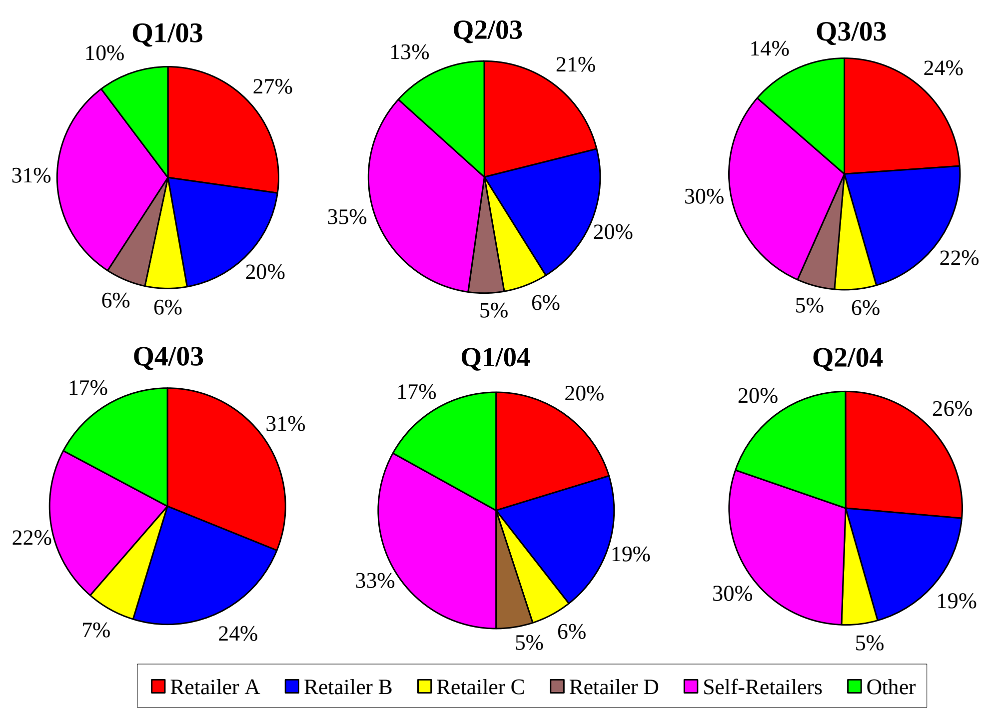
The MSA continues to track performance in the retail market based on the following metrics:

- Number of active retailers
- Retailer entry and exit from the market

- Market share (with respect to load) of retailers by customer class
- Trends in customer switching off the Regulated Rate Tariff (RRT) to sign competitive contracts.

As of June 30, 2004 there were 107 active retailers in the Alberta electricity market, 75 of which are self-retailers. Noteworthy in mid-Q2/04 was the closing of the transfer of retail energy supply businesses of ATCO to Direct Energy Marketing Ltd.. Under this agreement, Direct Energy has assumed retail functions including the supply of natural gas and electricity to former ATCO customers together with billing and customer service functions.

Figure 33 - Overall Market Share of Retailers by Load



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

Figure 33 shows the overall (all classes) market share of retailers for the last six quarters. In Q2/04, the distribution of market shares relative to last quarter showed some fluctuation, as the cumulative market share of retailers with at least 5% market share increased to 50% (retailers A, B and C) from 45% in Q1/04. The biggest change since Q1/04 is in the market share of the largest retailer increasing from 20% to 26% while growth in the “Self Retailer” category fell back slightly. The shift of load in Q2/04 from self-retail and other categories back to the leading retailer suggests that the major retailers have been successful in recouping market share lost in previous quarters although as **Figure 33** indicates, this has moved back and forth over the last several quarters. This movement of loads between retailers is viewed as a healthy sign of competition.

Figure 34 – Q2/04 Market Share of Retailers by Customer Class

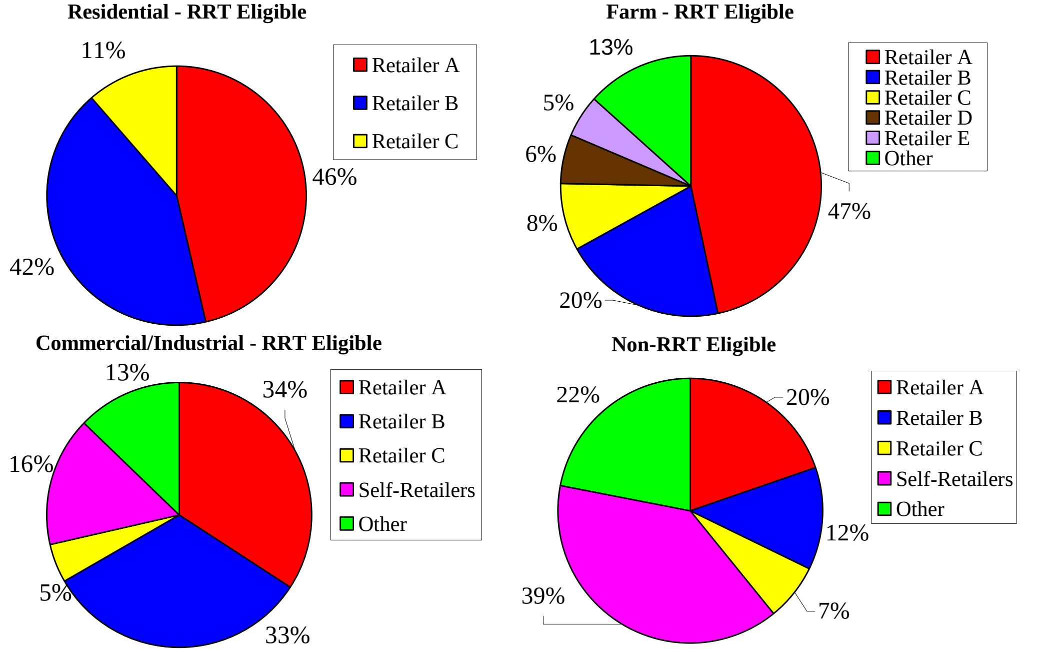


Figure 35 - Progression of Retailer Market Share by Customer Class

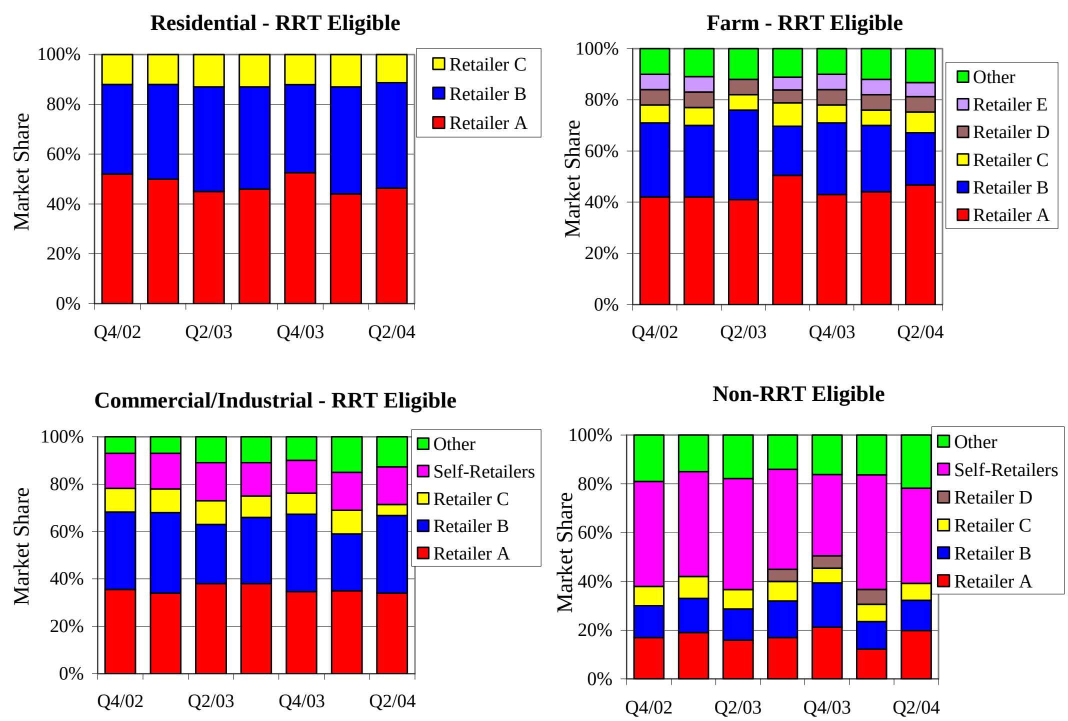


Figure 34 shows retailer market share by customer class for Q2/04 and **Figure 35** shows the progression of market share by customer class since Q4/02.

Market shares of the three dominant retailers in the Residential – RRT Eligible class have not materially changed over the last seven quarters. There has been some jockeying for position between the two largest retailers, but over the past seven 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. In the Farm – RRT Eligible category, market shares have also remained fairly static since Q4/02. However, some REA's are becoming more involved in retailing and this may have an effect on market shares in the Farm - RRT eligible category.

For Q2/04, market shares of the main retailers in the Commercial/Industrial – RRT Eligible category have declined and allowed for other retailers to gain ground in this category. The cumulative market share of the five retailers with at least 5% market share was 64% of the total load. Again, a trend towards to "self retailing" is apparent in this category as this has increased by 9% since last quarter.

The overall progression of customers off RRT to competitive electricity contracts has increased slightly this quarter. As of June 30, 2004, 7.4% of all RRT eligible customers have chosen to sign a competitive contract with a retailer, as shown in **Figure 36**. This represents a 0.3% increase since the end of Q1/04.

Figure 36 - Progression of RRT Eligible Sites Switching Off RRT

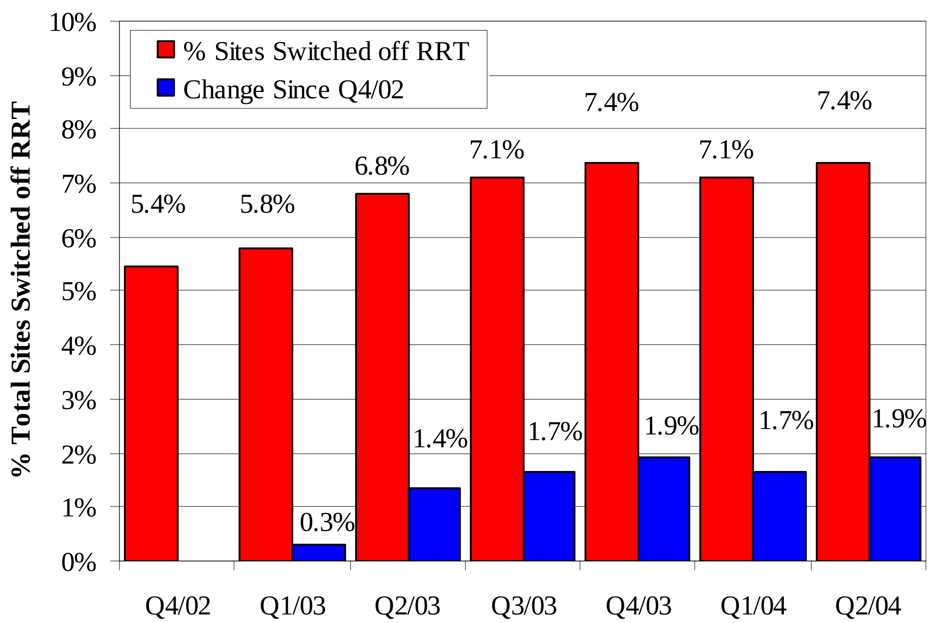


Figure 37 - Progression of RRT Eligible Sites Switching Off RRT by Customer Type

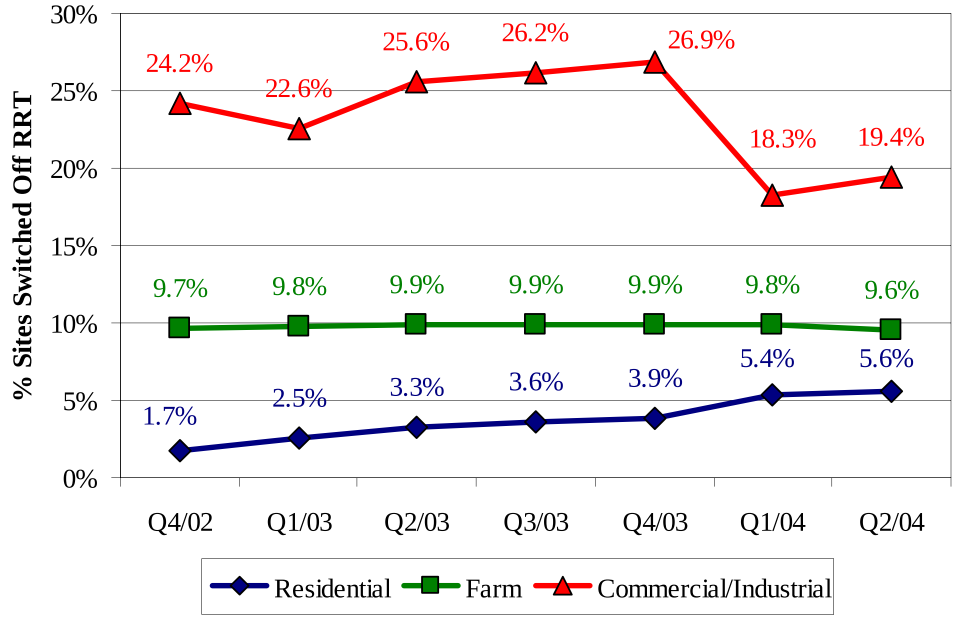


Figure 37 shows the progression of RRT eligible sites switching off RRT for the last seven quarters by customer type. Switching results are encouraging in the residential category where switching rates have increased slightly by 0.2% from 5.4% in Q1/04 to 5.6% in Q2/04.

Switching rates in the Commercial/Industrial – RRT eligible category are climbing slowly from when it dropped 8.6% in Q1/04 and is now at the level of 19.4%. 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.

3 MARKET ISSUES

3.1 TPG / IDP

The MSA published the Trading Practices Guidelines (TPG) and Information Disclosure Procedure (IDP) during Q1/04. The aim of the TPG is to level the playing field with respect to the use of asset outage information by participants for trading purposes. The MSA is of the view that the use of asset outage information in trading activities before this information has been publicly disclosed, runs contrary to the fair, efficient, and openly competitive operation of the market. Furthermore, non-public information held by market participants with large asset portfolios with respect to their outages creates a substantial information asymmetry in the market that is detrimental to forward market liquidity. Forward markets are key to any market participant or potential investor who needs to manage risk or secure predictable cost or revenue streams. The IDP provides market participants with a mechanism to comply with the TPG.

On June 10th, the MSA held a workshop with market participants and stakeholders that included a formal presentation and discussion of the TPG and IDP. The goal of the workshop was to solicit additional feedback and to demonstrate how the IDP will facilitate a fair, efficient, and openly competitive market.

As an outcome of the workshop, and subsequent feedback received from market participants, the MSA has resumed publishing outage reports effective July 5th on a twice daily basis, which reflect outage data compiled via the IDP.

The MSA continues to work with various parties to attempt to better handle the reporting of outage information related to load and transmission facilities. As well, the MSA is looking forward to receipt of the output from the market liquidity survey that was conducted late in June. As discussed elsewhere, the results of this survey may form a baseline from which the MSA can compare the effect of the IDP initiatives.

For further reference on TPG and IDP, please refer to the following location on the MSA website: http://www.albertamsa.ca/TradingPracticesGuidelinesandInformationDisclosureProcedure.html .

3.2 Market Design Initiatives

The MSA has been participating for the past quarter on an initiative established by the Alberta Department of Energy operating under the name "Wholesale Market Policy Task Force" (WMPTF). The task force includes participation from groups representing load, supply, infrastructural agencies and the DOE. The process so far has enumerated a range of possible market issues. The interrelationships between the issues and the merits of and connections between potential solutions will be considered in a holistic fashion during the WMPTF's next phase this fall.

One issue that has been raised by the task force but about which there is little empirical data is the liquidity of the forward market. To that end the AESO under the auspices of the WMPTF and with the assistance of the MSA, commissioned a survey designed to shed further light on the question - who was buying, selling, trading? How often, how much volume, why, why not, satisfaction level with current liquidity? The detailed responses were provided on a confidential basis and are presently being aggregated and stripped of identifying details by the survey consultant for rendering to the WMPTF. The survey should also provide a baseline for the MSA to use next year in quantifying improvements to liquidity that may be related to the Trading Practices Guideline.

3.3 MSA Stakeholder Survey

In May 2004, the MSA commissioned a survey of market stakeholders to solicit views and feedback on how effectively the MSA fulfills its mandate and responsibilities in the Alberta electricity market.

The survey was conducted by an independent third party with the MSA providing assistance in design of the questionnaire and in compiling the contact list.

While survey respondents saw the MSA as being visible, approachable, and proactive, some felt the MSA could do more to enhance confidence and promote transparency.

This survey was designed to develop a baseline from which the MSA can enhance its function to fully meet the expectations of all stakeholders and the results will shape our approach going forward. We expect to conduct similar surveys on an annual basis in order to keep close touch on the views of our stakeholders.

To review the consultant's summary report of the survey results, go to: http://www.albertamsa.ca/files/Final_eReport_25_06_04.pdf

3.4 Regulating Reserve Study

The MSA is currently engaged in a study of the impact of regulating reserve on the Alberta electricity market. Units providing regulating reserve respond automatically to the Area Control Error (ACE), which in turn is driven by the difference between the actual and scheduled system frequency and the actual and scheduled interchange schedule on the interconnection with British Columbia.

The motivation for the study has arisen from the observation that, at times, small blocks of energy have set the system marginal price (SMP) for extended periods of time. Although this, in and of itself, is not considered problematic, it has raised the interest of a number of participants as to whether there has been over-reliance on energy from the regulating range rather than dispatching through the merit order.

The study examines the System Coordination Center's (SCC) responsibilities as a member of the Western Electric Coordinating Council (WECC) with respect to the use of regulating range and energy and the control performance standards (CPS) that are used to evaluate and assess system performance.

The study also focuses on overall system dynamics, such as the statistical relationship between regulating energy, area control error (ACE), load and SMP. Finally the study examines in detail a number of incidents where small blocks have set SMP to help understand the interplay between load, generation, offer behaviour, imports and exports, regulating reserves and the SMP.

At a minimum, it is anticipated that this study will assist market participants in understanding the challenges, responsibilities and tools available to the SCC in meeting its responsibility to operate the system within the standards set by WECC.

The study is ongoing and will require further analysis prior to publishing results.

3.5 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 within the province.

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 MSAs observations will tend to be more directional in nature, identifying trends in the indicators as the settlement process develops.

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 Q2/04.

Table 5 - PFEC and PFAM Tracking

Claim Type	Carry-Over	Submitted	Accepted	Rejected	Unresolved	Net kWh Adjustment
PFEC						
Q1/04	803	166	935	2	32	NA
Q2/04	32	396	307	19	102	NA
PFAM						
Q1/04	6,958	2,089	7,500	138	1,409	(57,357,137)
Q2/04	1,409	293	708	674	317	(9,535,801)

The table shows that the number of PFECs submitted has increased substantially from last quarter and a substantial number still remain unresolved. This will be monitored to ensure the PFECs continue to be dealt with in a timely manner.

The volume of PFAMs submitted declined significantly during Q2. The decreasing number of unresolved PFAMs suggests that the LSAs are improving their processes for dealing with complaints. The increase in unresolved PFEC's is partially a function of the increase in the number submitted.

UFE

The MSA has 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
Q1/04	8	11	6	13
Q2/04	13	8	3	18

At the end of Q1/04 there were 13 unresolved UFE reports. By Q2/04 this number increased to 18 while new reports in the period declined. This suggests that the LSA's may not be dealing with exceeded UFE tolerances in an efficient manner[4]. 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 by the end of the

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

next quarter. As the settlement process matures, the MSA would hope to see an improvement in the turn around time for dealing with UFE reports.

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.

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.

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

	Non-Compliance Notices Issued				Enforcement Escalation Notices Issued	Enforcement Withdrawal Notices Issued
	Level 1	Level 2	Level 3	Level 4		
Jan	0	0	0	0	0	0
Feb	4	0	0	0	0	0
March	1	1	0	0	0	0
April	0	0	0	0	0	0
May	0	0	0	0	0	0
June	0	0	0	0	0	0
YTD Total	**5**	**1**	**0**	**0**	**0**	**0**

The table shows that to date five 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. The second quarter experienced no non-compliance notices from the AESO.

[5] See Section 4 of Appendix C of the SSC.

4 OTHER MSA ACTIVITIES

4.1 MSA Website

Incremental enhancements were recently made to the MSA website. The homepage of the website now more clearly displays the list of most current items so as to better highlight new content.