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MSA REPORT

Quarterly Report

July – September 2003

29 October, 2003

MARKET SURVEILLANCE ADMINISTRATOR

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Market Highlights

- The average price of electricity in the Alberta wholesale spot market in Q3/03 was $62.59/MWh; up from $50.94/MWh last quarter. Average Pool price for 2003 year to date was $65.75/MWh vs. $38.06/MWh for the same period a year ago.

- Alberta spot gas prices moved lower in Q3/03 relative to the prior quarter as average price decreased to $5.54/GJ from $6.47/GJ. This contributed to an increase in the on-peak average implied market heat rate to 13.7 GJ/MWh in Q3/03 from 9.8 GJ/MWh in the prior quarter.

- Although average Pool price moved higher in Q3/03, price volatility was lower in Q3/03 relative to both last quarter and Q3/02.

- The outage rate for PPA coal units (excluding planned outages) increased in Q3/03 although availability of PPA coal units for 2003 year to date remained ahead of target availability.

- Export volumes to Powerex decreased slightly in Q3/03 as compared to last quarter but reached a 15 month high in September. Energy flows on the tie lines in Q3/03 corresponded well with the economically implied flow direction.

- The MSA conducted a review of its approach to monitoring of outages and derates and a synopsis of its internal report is presented herein.

1 REVIEW OF THE WHOLESALE ELECTRICITY MARKET

1.1 Electricity Prices

The MSA's interest in Pool price is to the extent that Pool price is determined by market forces in a fair, efficient, and openly competitive manner. As the MSA has indicated publicly on several occasions, the MSA is not for high prices or for low prices, only competitive prices which are determined in the aforementioned way.

On a monthly average basis, pool prices were higher in Q3/03 as compared to both last quarter and the same period a year ago on both an on-peak and an off-peak basis, as shown in **Figure 1** and **Table 1**. Pool prices were higher in Q3/03 overall, due to strong on and off peak prices in July attributable in large measure to coal unit outages (see 1.12 Outages and Derates) and this pulled up the averages for the quarter significantly. Although prices were higher overall in Q3/03, prices did decline month on month through the quarter with an average price in September of \$43.63/MWh. The price duration curves shown in **Figure 2** show that although prices in Q3/03 were higher the majority of the time relative to last quarter and to Q3/02, Q3/03 prices remained in a more consistent range as shown by the flatter center portion of the graph for Q3/03. **Figure 2** also demonstrates that price spikes were limited in duration and were similar in Q3/03 relative to last quarter although somewhat more frequent than the same quarter last year. As noted previously, prices in Q3/03 were more stable the majority of the time which is reflected by lower relative volatility (as defined here by coefficient of variation) than last quarter and the same quarter last year.

Table 1 - Pool Price Statistics

	Average Price	On-Pk Price	Off-Pk Price	Std Dev[1]	Coeff. Variation[2]
Jul -03	87.91	106.25	64.64	98.72	112%
Aug -03	55.63	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%**
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%**
Jul -02	26.41	36.16	14.06	41.48	157%
Aug -02	32.03	41.27	19.22	52.58	164%
Sep -02	45.70	61.43	27.72	42.16	92%
Q3 / 02	**34.59**	**46.29**	**20.33**	**46.41**	**134%**

1 - Standard Deviation of hourly pool prices for the period

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

Figure 1 - Pool Price with Pool Price Volatility

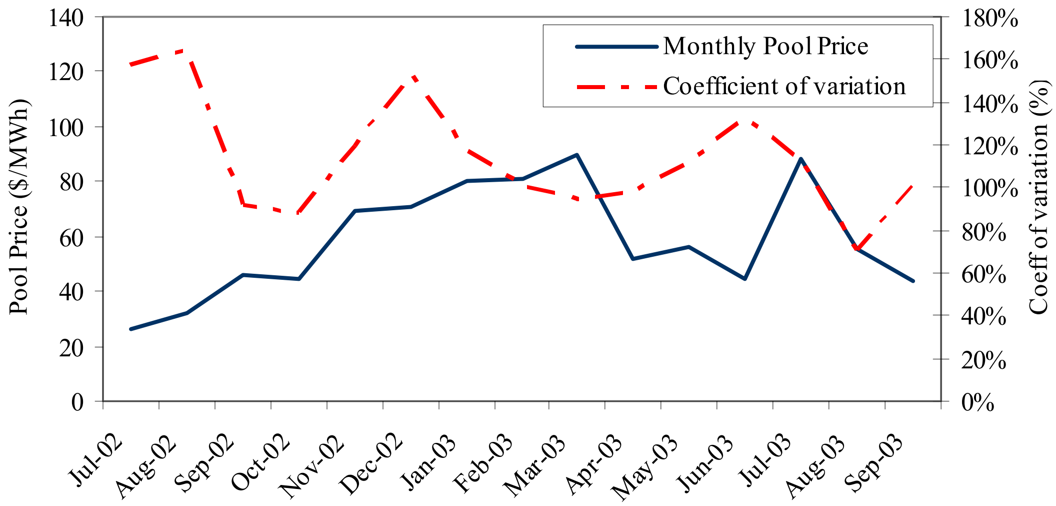
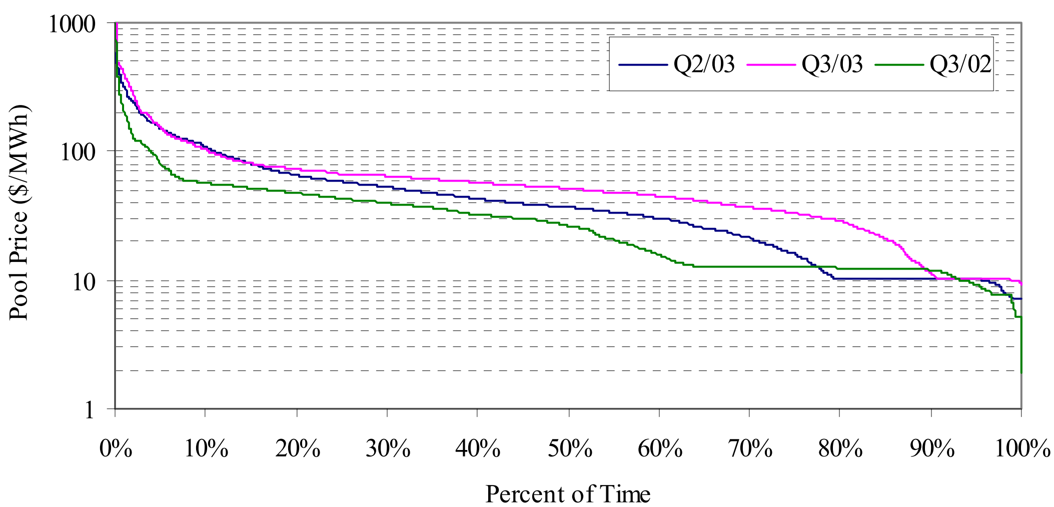


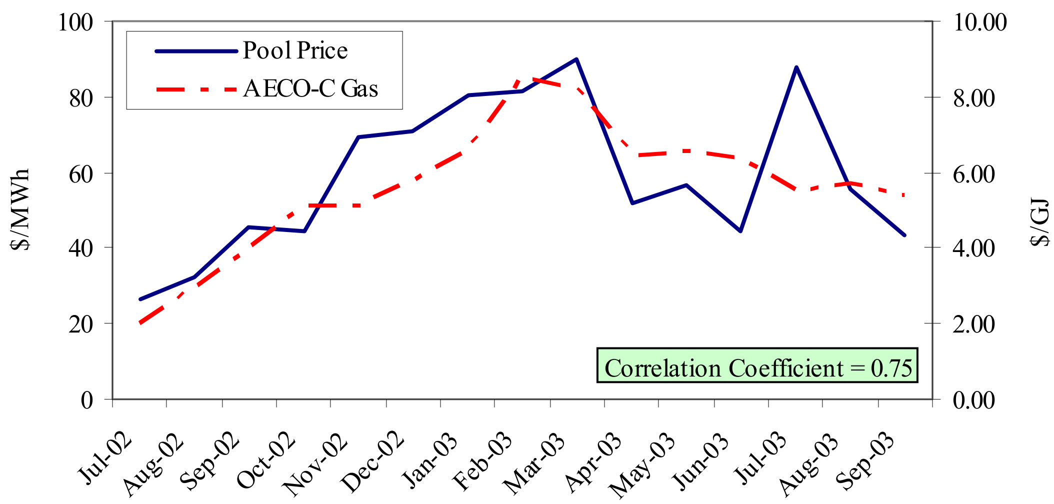
Figure 2 - Quarterly Pool Price Duration Curves



1.2 Natural Gas Prices

Alberta gas prices declined in July and remained in the $5.50/GJ range for the balance of the quarter as can be seen in **Figure 3**. This was approximately $1.00/GJ lower than the average level of gas prices observed last quarter. The correlation between Pool prices and Alberta gas prices weakened somewhat in Q3/03 as the rolling 15 month correlation between pool price and Alberta gas prices for the period ending September 30/03 was 0.75 as compared to 0.83 for the 15 month period ending June 30/03. Gas fuelled units set marginal pool price more frequently in Q3/03 relative to Q2/03 and one might expect that as a result, the correlation of pool prices and gas prices should strengthen. The results to the contrary suggest that although gas units set marginal price more frequently, their offer behaviour was less tied to short-run marginal cost.

Figure 3 - Pool Price with AECO Gas Price



1.3 Price Setters

Figure 4 shows the profile of the 5 most frequent price setting participants through Q3/03 and Q2/03 together with the weighted average price at which they set system marginal price (the individual price setters are not necessarily the same parties at each ranking). The leading price setter in Q3/03 set the system marginal price just under 30% of the time at a weighted average SMP of $61.17/MWh (all hours basis) which is below the average pool price of $62.59 for the quarter. Price setting was dispersed to a greater extent in Q3/03 as the top 5 price setters were the marginal price setters 69% of the time vs. 86% in Q2/03. This suggests that no one generator dominated the marginal price of wholesale electricity in Q3/03.

Figure 4 - Price Setters By Participant, Q3/03 and Q2/03 (All Hours)

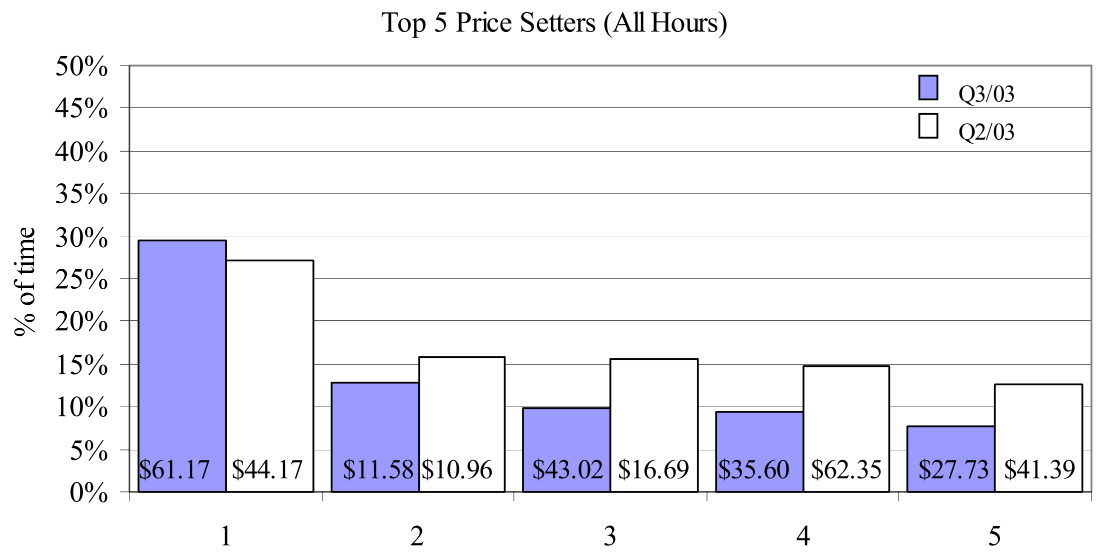
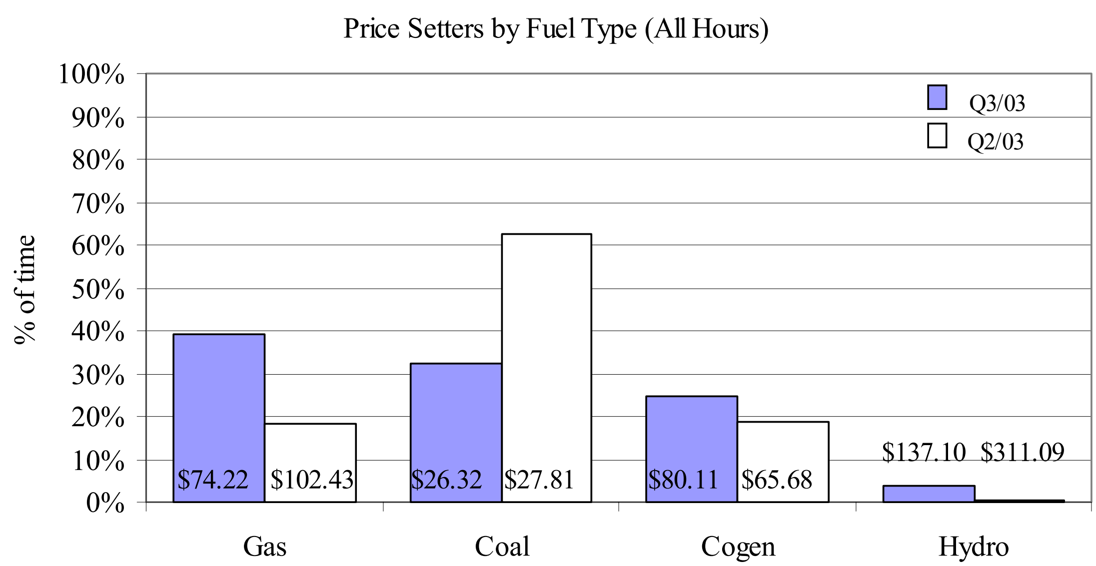


Figure 5 shows the price setting breakdown for Q3/03 and Q2/03 by fuel type of the price setting unit. Q3/03 showed a significant shift in the price setting frequency of gas units (including co-gen) relative to coal units as gas units set price 64% of the time on an all hours basis as compared to 32% of the time for coal units. In the previous quarter, gas units set price 37% of the time while coal set price 62% of the time. Gas units are typically the marginal units the majority of the time on an all hours basis although this was not the case in Q2/03 as a result of the low market heat rates in that period.

Figure 5 - Price Setters by Fuel Type, Q3/03 and Q2/03 (All Hours)



1.4 Implied Market Heat Rate

The implied market heat rate (IMHR) provides a basis to assess the profitability of the market from the perspective of both current and new potential market entrants. **Figure 6** shows the daily implied market heat rate for Q3/03 on an all hours basis. As shown in both **Figure 6** and **Table 2**, implied heat rates moved higher in both on-peak and off-peak periods with an average on-peak IMHR of 13.7 GJ/MWh in Q3/03 vs. 9.8 GJ/MWh in the previous quarter. On an off-peak basis, IMHR improved to 7.9 GJ/MWh from 4.9 GJ/MWh in the previous quarter. Although IMHR's were stronger quarter over quarter, it can be seen in **Figure 6** that there was a generally decreasing trend through Q3/03.

Figure 6 - Implied Market Heat Rates, Q3/03

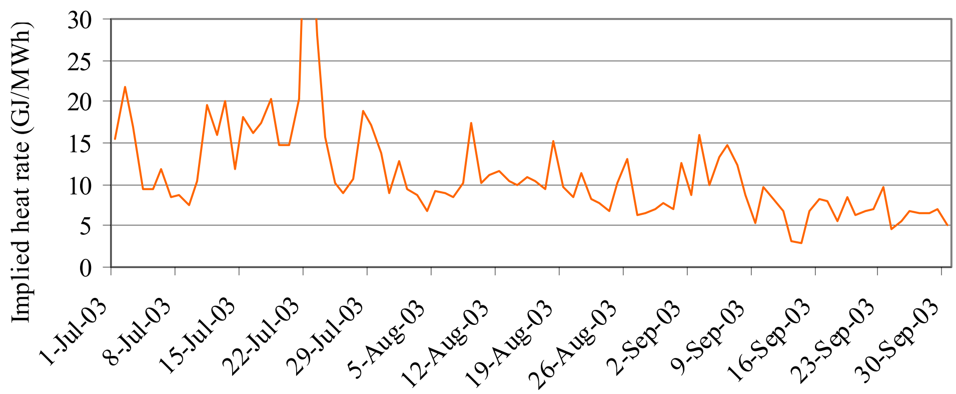


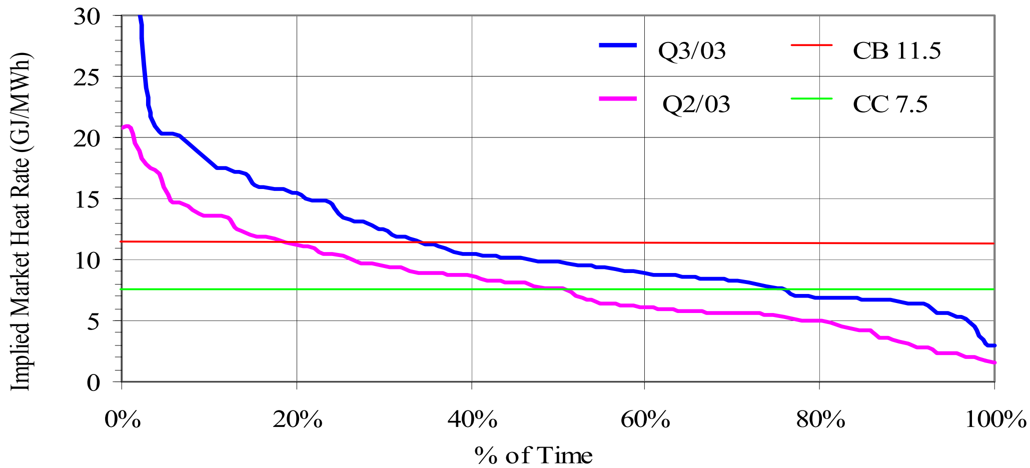
Table 2 - Implied Market Heat Rates; Q2/03 and Q3/03

Month	On-Peak	Off-Peak	All Hours
Apr	9.7	5.6	8.0
May	11.3	5.5	9.1
Jun	8.7	3.8	6.8
Q2/03	*9.8*	*4.9*	*7.9*
Jul	19.2	11.3	15.9
Aug	11.6	7.1	9.7
Sep	9.8	5.0	8.1
Q3/03	*13.7*	*7.9*	*11.4*

Figure 7 provides some further context to the heat rate levels observed in Q3/03 and in the prior quarter. The figure shows implied heat rate duration curves for the last two quarters with the approximate heat rates of Clover Bar (CB; 11.5 GJ/MWh) and a new combined cycle plant (CC; 7.5 GJ/MWh) superimposed, representing the two ends of the efficiency spectrum among gas-fired units in the Alberta system. In Q3/03 a new

combined cycle plant would have been in a position of operating while at least recovering its fuel costs about 76% of the time, however, the same plant would have been able to operate and cover its fuel costs only 52% of the time in the previous quarter.

Figure 7 - Heat Rate Duration Curves; Q3/03 and Q2/03 (All Hours)



1.5 New ISO Rules

The Alberta Government proclaimed the new *Electric Utilities Act* (EUA) on June 1, 2003. The Act, among other things, integrated the functions of the Power Pool, the Power Pool Administrator, the System Controller and Transmission Administrator under the Independent System Operator (ISO), known as the Alberta Electric System Operator (AESO). Also under the new Act, the Balancing Pool and the MSA became independent entities, with the Balancing Pool Reporting to a newly formed Balancing Pool Council, and the MSA reporting to the Chairman of the Alberta Energy and Utilities Board (AEUB).

As part of its mandate, the AESO has consolidated the Power Pool Rules, Power Pool Code (Code), Transmission Administrator Operating Policies (TAOPs), and Settlement System Code into an amalgamated ISO Rules document. The ISO document contains two broad categories. The first is Market Participant Rules, which represent the combination of the Power Pool Rules and the Settlement System Code. The second is Operating Policies and Procedures (OPPs), which combine the Pool Code and the TAOPs. The amalgamated document came into effect July 28, 2003. In addition, the EUA contemplates that the ISO will establish a schedule of fees and charges and administrative penalties, which although not rules or operating procedures, are included in the ISO Rules document for convenience.

The new ISO Rules document is not intended to create substantive changes to existing rules and operating policies but rather to create a single document that complies with the new EUA. However, over the course of Q3/2003, subsequent to the issuance of the new Rules document, there have been several rule and operating policy changes approved, as outlined below.

Rule Change Classification

On August 15, 2003, the AESO proposed a number of rule changes, for implementation on September 30, 2003. In order to facilitate the rule change process and consultations, the AESO categorized the rule changes as follows in relation to their expected level of significance:

Level I are those changes having a significant operational or financial impact on the industry or ISO. These changes typically require working group input and/or extensive stakeholder consultations to implement the effective solution.

Level II are changes that are expected to have a moderate to low impact on the industry or the ISO, and generally require little to no effort by stakeholders for implementing a solution. They are provided to stakeholders to review to ensure that the expected impact is reasonable, to identify unrealized impacts and/or to provide notice of the potential change in the administrative process.

Level III are administrative changes that do not intend to impact the meaning and/or implementation of the rules. They are provided to stakeholders for review to provide transparency and ensure that the zero impact intent is maintained.

All Level I and II rule changes are approved through the Executive Rules Change Committee at the AESO.

Some of the rule changes which came into effect on September 30, 2003 are set out below.

Participant Rule Changes

Locking Restatement Guideline – Rule Integration: Market Participant Rule 3.5.2(b) – (Level II change)

The Guideline for use of the locking restatement was approved by the Power Pool Council on June 13, 2002. It has been integrated as a rule to facilitate participant understanding of operational implications of the locking restatement in a central locale, rather than searching for “guidelines” separately from “rules”.

MSA Access to Information: Market Participant Rule 10.9.1 Confidentiality Obligations - (Level III change)

The wording of the rule has changed from "The ISO will provide the Market Surveillance Administrator access to confidential information." to "In accordance with the Act and related regulations, the ISO will make available to the Market Surveillance Administrator confidential information and other records relating to market participants that are held by or become available to the ISO pursuant to the Act." This rewording is designed to better align Rule 10.9.1 with the *Market Surveillance Regulation.*

Definition of the MSA, G1 Definitions

The definitions within the Rules document have been amended to include a definition of the MSA, to cross reference the Market Surveillance definition in the Act. The definition is as follows: "Market Surveillance Administrator" (MSA) has the same meaning as given in the Act".

Operating Policies and Procedures (OPP) Changes

There have been a number of OPP changes approved by the AESO since the approval of the Rules document. OPP 002, *Change Management Process*, outlines the new process for developing and revising Operating Policies and Procedures. Details can be found on the AESO's website at: http://ets.powerpool.ab.ca/downloads/opp_002_finalDraft.pdf. Revisions to Operating Policies include OPP 503 *Revision of Empress Area Security* (http://ets.powerpool.ab.ca/downloads/opp_503_Draft.pdf) and a Revision of OPP 804 *Off Nominal Frequency Load Shedding and Restoration* (http://ets.powerpool.ab.ca/downloads/opp_503_finalDraft.pdf). The AESO has also withdrawn OPP 506 *Fort Saskatchewan Area Operating Procedures* and OPP 511 *Janet 138kV South Bus Operating Procedures*. These Operating Policies have been withdrawn due to the commissioning of the Josephburg and Beddington substations, which have relieved concern around transmission line overloading in these areas, making these OPPs unnecessary.

Settlement System Code

Load Settlement Compliance Enforcement – (Level I change)

This rule change seeks to define responsibilities, processes, and actions to be taken by the ISO and other market participants in the event of non-compliance to the ISO rules governing load settlement. Pursuant to the Act, the ISO has the duty to regulate and administer load settlement, and to enforce ISO rules.

A complaint regarding the contravention of a load settlement rule may be initiated by another market participant, or the ISO itself.

Where the ISO determines that there has been a contravention of a load settlement rule by a market participant, the ISO will assess the contravention level. The ISO will then work with the non-compliant party toward rectifying the non-compliance.

Not to be confused with the AESO's rule change classification, Settlement System Code contravention terminology also uses the term "Level" to denote severity of the contravention.

The levels for contravention of a load settlement rule are as follows:

Level One: Minor Contravention

These are contraventions that have little or no impact on market participants involved in load settlement or their processes.

Level Two: Major Contravention

These are contraventions that have a significant impact on market participants involved in load settlement or their processes.

Level Three: Serious Contravention

These are contraventions that impact settlement of the market.

Level Four

These are contraventions that are deliberate, intentional, deceptive, or fraudulent.

Where the ISO has assessed a contravention, it will determine appropriate enforcement actions within that level of assessment. The ISO may provide timelines and schedules for completion of these actions.

1.6 New Supply and Load Growth

No significant new generation was brought on line during Q3/03 although year to date, 250 MW of new generation was added to the system.

The monthly average hourly system demand for electrical energy in Q3/03 was:

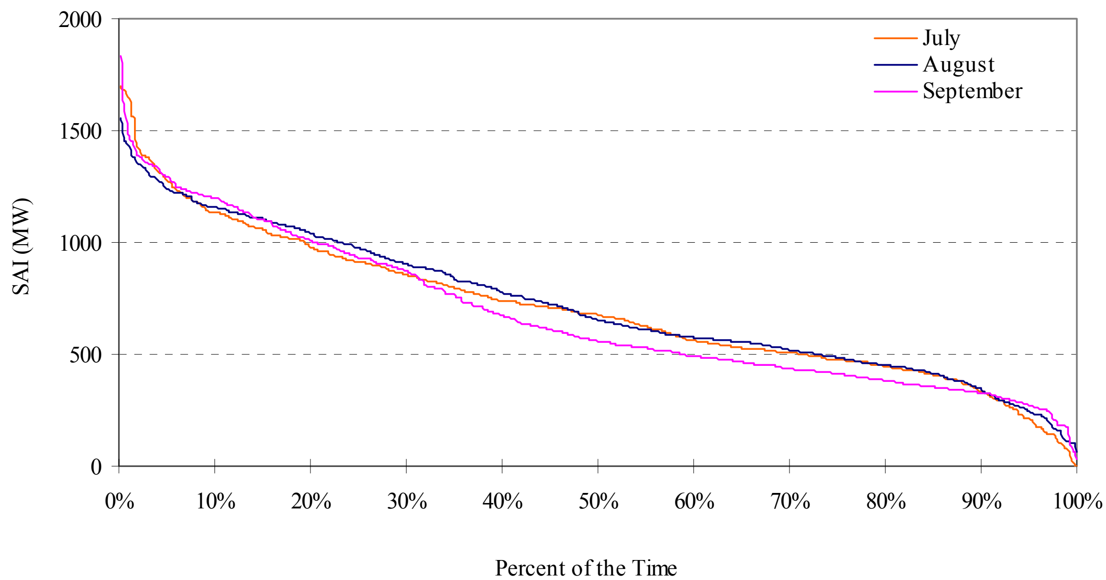
- July 7095 MW +0.1% vs. July 2002
- August 7172 MW +5.1% vs. August 2002
- September 7016 MW +3.2% vs. September 2002

Peak demand in Q3/03 was 8295 MW which occurred in HE 16 on July 31 at a pool price of $76.00/MWh. Peak demand in Q3/03 increased approximately 1% from peak demand in the same period a year ago.

1.7 Supply Availability Index (SAI)

SAI is a metric defined by the MSA to assess market supply demand tightness based on the remaining volume of energy in the merit order above the dispatch level for each hour. This measure is intended to reflect the supply available to the System Controller intra-hour (within the hour). **Figure 8** shows the SAI for each month in the quarter in a duration curve format. **Figure 8** shows that the month of September had the lowest mean SAI in Q3/03, however, for that portion of the curve where the SAI is at its lowest (ie: between 90% and 100% on the horizontal axis), the month of July was the tightest . It is at very low SAI values where price response tends to be most pronounced, and as would be expected, July was the highest price volatility month in the quarter. Relative to the prior quarter, average supply availability decreased 5% from 812 MW in Q2/03 to 768 MW in Q3/03. Availability and price are generally negatively correlated. It is important to note that the strength of this correlation varies with the shape of the supply offer curve in that less price response is seen the more flat the supply curve happens to be and vice versa. In Q3/03, the correlation coefficient between SAI and hourly pool price was determined as – 0.44. This compares to -0.47 in Q2/03 and indicates that the correlation weakened slightly in Q3/03 relative to the previous quarter.

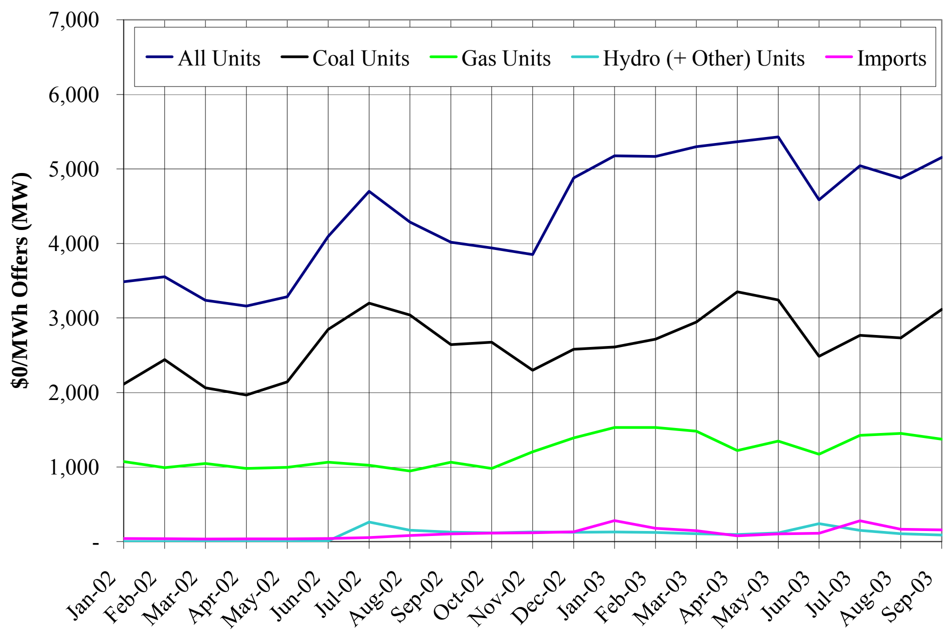
Figure 8 - SAI Monthly Duration Curves, Q3/03



1.8 Zero Offers

The MSA has made a commitment to periodically report on zero offer behavior in the Alberta electricity market. **Figure 9** plots monthly average MW offered at $0/MWh by unit type for 2002 and 2003 to date.

Figure 9 - Zero Dollar Offers



The figure shows that after reaching an all-time high in May 2003, total zero offers seem to have leveled off in Q3/03. Average zero offers for the quarter were 5,025 MW. This is a 101 MW decrease from the Q2/03 average of 5,126 MW but a 690 MW increase from the Q3/02 average of 4,335 MW.

Total zero offer volumes continue to be primarily influenced by coal unit zero offers. Variability in coal unit zero offers tends to be highly related to coal unit outages since most coal units offer at least some of their capacity at $0/MWh and when a unit is unavailable, it is not offered into the market. As such, a change in zero offer volume tends to reflect a similar directional change in coal unit availability. Zero offer behavior of gas units, hydro units, and imports did not change significantly over the course of the quarter.

Although zero offers persist, they do not appear to be increasing or changing in a way that the MSA finds detrimental to the operation of the market. The MSA will continue to monitor zero offer behavior but will only report on zero offers if they appear to be having a significant effect on the fair, efficient and openly competitive operation of the market.

1.9 Imports, Exports, and Prices in Other Electricity Markets

The interconnections between Alberta and neighboring markets/jurisdictions play an integral part in the operation of the Alberta electricity market. Tie-line activity can effectively increase or decrease either supply or demand in the market by as much as the tie-line capacity and therefore has a significant impact on Pool price. The prices in other markets also affect the activity on the interties which in turn has an impact on activity (and price) in the Alberta market. **Table 3** summarizes the activity on the tie-lines for Q3/03.

Table 3 - Tie Line Activity Q3/03

	BC			Saskatchewan			Overall		
	Imports	Exports	Net Imports	Imports	Exports	Net Imports	Imports	Exports	Net Imports
	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
Jul	105,400	80,100	25,300	37,500	200	37,300	142,900	80,300	62,600
Aug	52,700	100,700	(48,000)	41,700	4,000	37,700	94,400	104,700	(10,300)
Sep	54,100	140,100	(86,000)	12,700	2,600	10,100	66,800	142,700	(75,900)
Total	**212,200**	**320,900**	**(108,700)**	**91,900**	**6,800**	**85,100**	**304,100**	**327,700**	**(23,600)**
On-Peak	87%	6%		51%	58%		76%	7%	
Off-Peak	13%	94%		49%	42%		24%	93%	

Note: Negative net imports indicate net exports

In Q3/03, Alberta was an overall net exporter. Exports are dominated by activity on the BC tie-line (98%) – primarily in the off-peak hours. Exports increased throughout the quarter while imports decreased. This is likely the effect of higher Pool prices in July and more modest prices towards the end of the quarter. High levels of exports in September are also likely the result of BC Hydro buying energy from Alberta for use within BC in lieu of drawing down the storage in their reservoirs.

Figure 10 - Market Share of Importers and Exporters, Q3/03

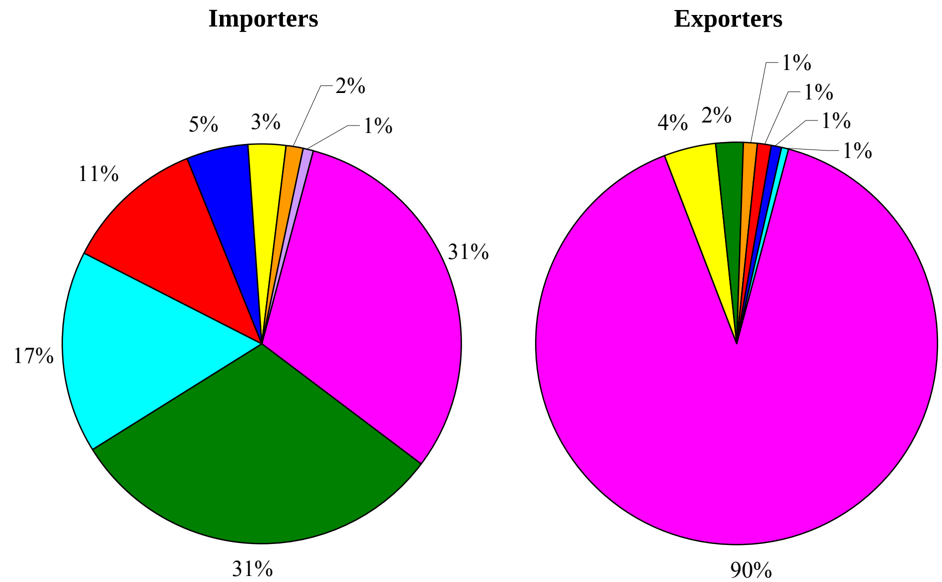
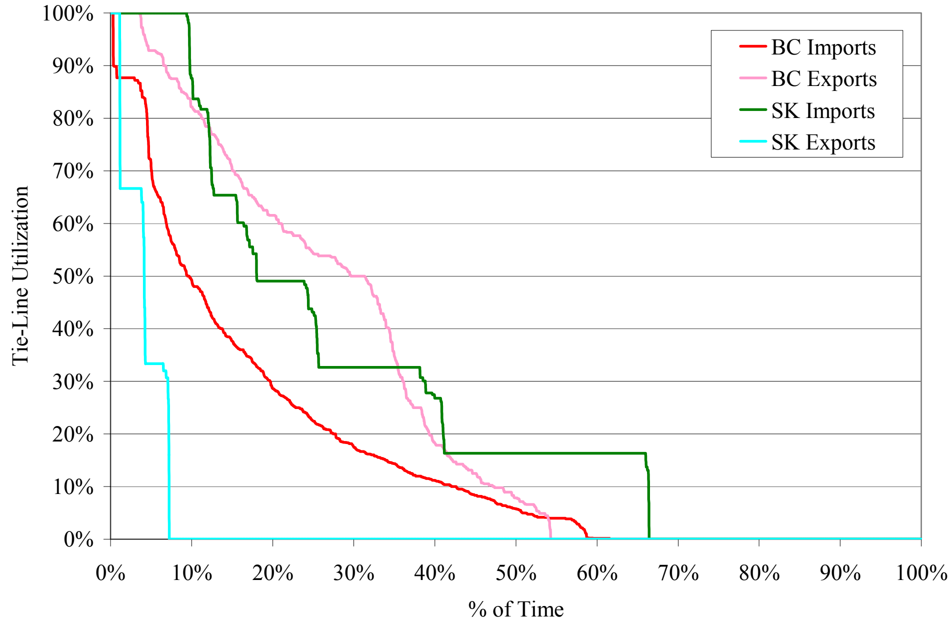


Figure 10 shows the distribution of market shares of importers and exporters on the BC and Saskatchewan tie-lines (combined) in Q3/03. Market share of importers is fairly well distributed with no importer having more than a 31% market share and four importers having market shares of 10% or greater. Market share of exporters is dominated by one participant: Powerex. This is not surprising as Powerex holds all firm transmission rights on the BC tie-line and generally makes use of its export transmission capacity in all off-peak hours.

Figure 11 shows a duration curve of tie-line utilization in Q3/03 as a function of available transfer capability (ATC) – 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 40%. ATC is posted on the AESO website and varies on an hourly basis.

Figure 11 - Tie Line Utilization



The figure shows that there is unutilized tie-line capacity available on all of the tie-lines almost all of the time. The Saskatchewan export line is the most underutilized tie-line on a percentage basis. Note that we would not 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, Pool price and market position contribute to determining whether or not it is profitable to make use of the available tie-line capacity. Note that there were no significant tie-line outages in Q3/03, but those few hours of tie-line outage were removed from the sample.

Activity on the tie-lines can be highly dependent on Pool price. **Figures 12** and **13** 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 2002 through September 2003 period. During Q3/03, 76% of imports occurred during on-peak hours and 93% of exports occurred during off-peak hours, therefore comparisons with on and off-peak prices are appropriate.

Figure 12 - Imports and On-Peak Pool Price

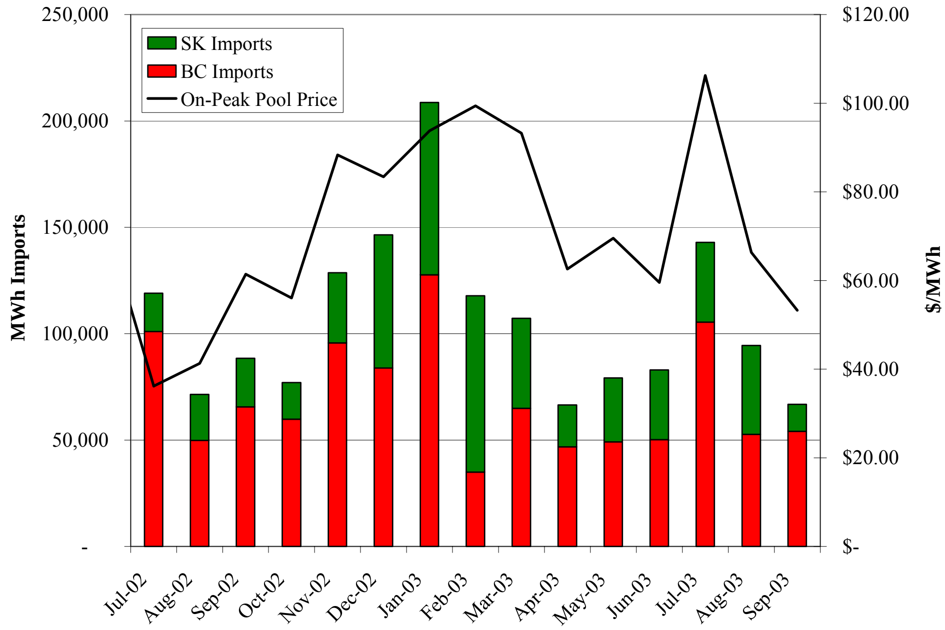
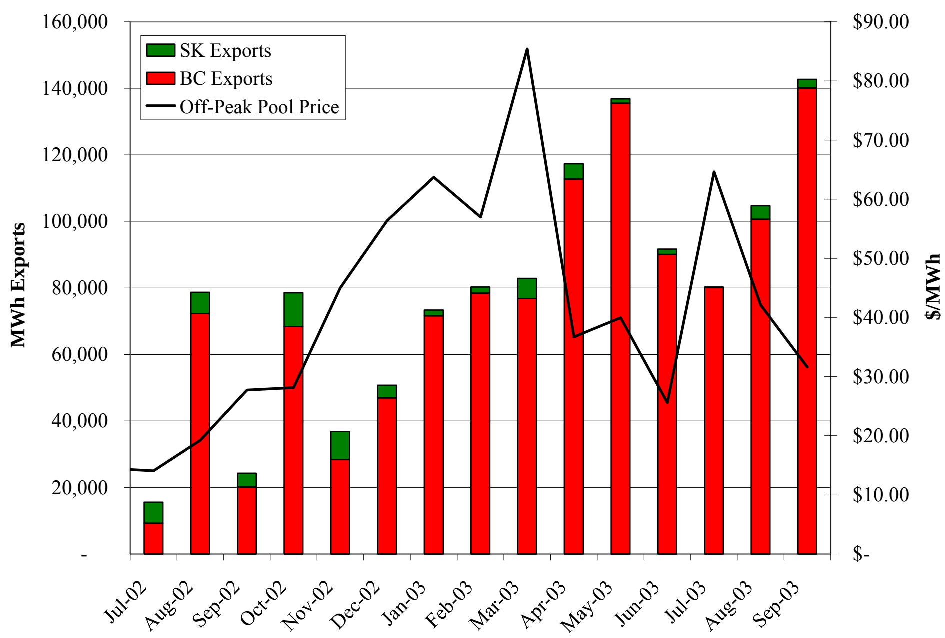


Figure 13 - Exports and Off-Peak Pool Price



Import volumes correspond well with on-peak Pool prices – as price increases, the volume of imports increase. Both prices and import volumes have increased in Q3/03 from Q2/03. The average on-peak Pool price in Q3/03 was $75.28/MWh with a total of over 304,000 MWh of electricity being imported compared to 229,000 MWh being imported at an average price of $63.90/MWh in Q2/03. Large import volumes (particularly from BC) and high prices in July are a major contributor to the increase. Although the average on-peak price in Q3/03 was significantly higher than the on-peak price in the same period last year, import volumes are not substantially different. This indicates that price is not the only factor affecting import volumes.

During Q3/03 the inverse relationship between off-peak Pool price and export volumes is clear. Exports (primarily on the BC tie-line) fell in July and then rebounded to reach a 15-month high in September. Average exports for the quarter were slightly lower than for last quarter (327,700 MWh in Q3/03 vs. 345,800 MWh in Q2/03). Q3/03 exports, however, were approximately three times higher than in the same period last year. Export activity is increasingly dominated by the BC tie-line. Only 6,800 MWh of electricity flowed on the Saskatchewan tie-line in Q3/03 compared to 7,500 MWh last quarter and 16,900 in Q3/02. Exports to Saskatchewan reached an all-time low in July 2003 with only 200 MWh of exports. Note that the Saskatchewan tie-line did not experience any major outages during the period and low export volumes are therefore attributed to market conditions.

Prices in other markets also have an impact on the economics of importing and exporting 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 into adjoining markets. **Figures 14** and **15** show monthly average on-peak and off-peak price indices for MAPP-North (US Mid-West), Mid-C (US Pacific Northwest) and North-Path 15 (California) compared to Pool price. All prices are in Canadian dollars and have been converted at an exchange rate of 1.40 CDN/US.

Figure 14 - On-Peak Pool Price and Prices in Other Markets

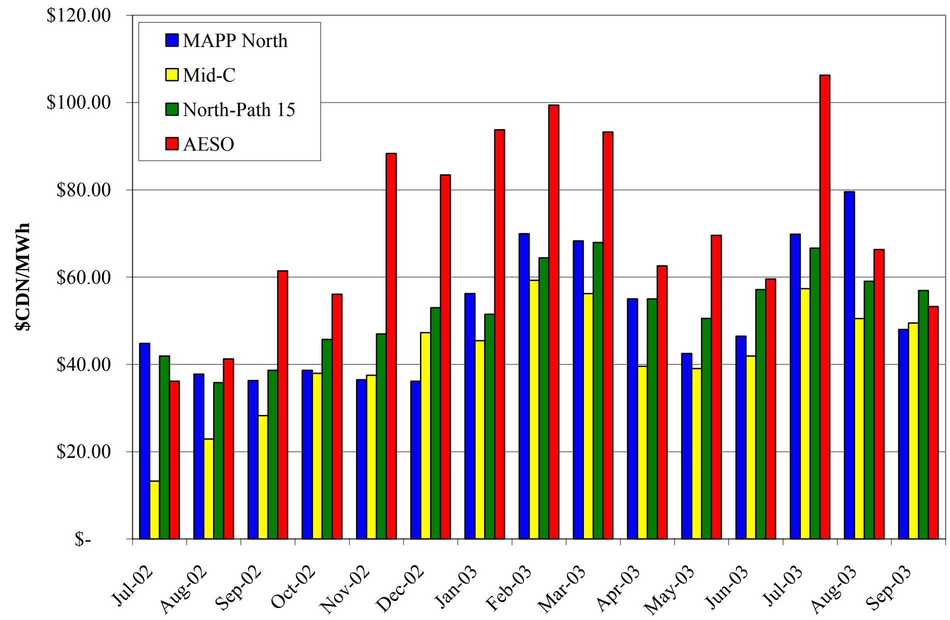
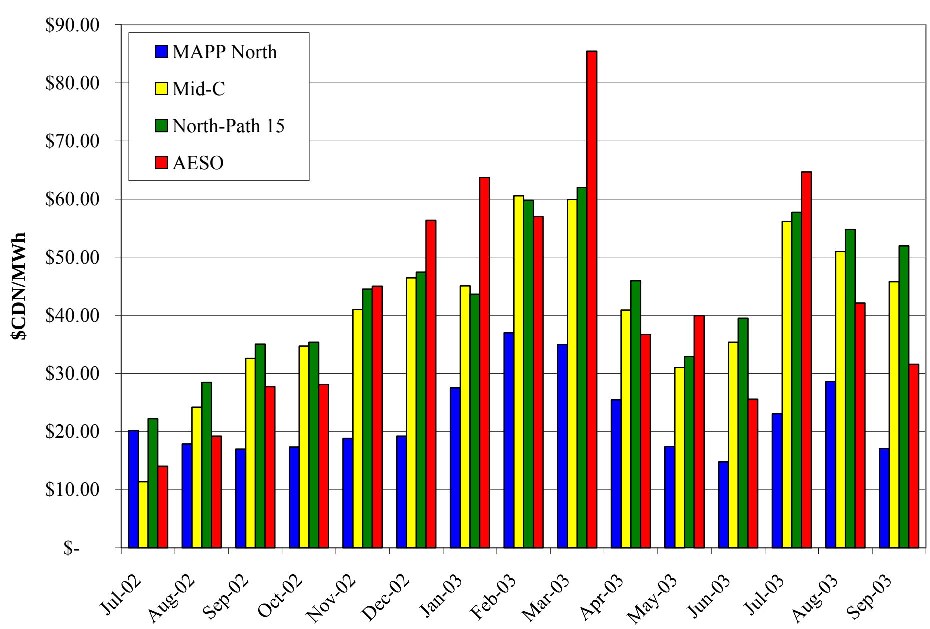


Figure 15 - Off-Peak Pool Price and Prices in Other Markets



On-peak prices in Alberta started strong this quarter but decreased during August and September. On-peak prices in other markets generally followed the same trend but differences were less extreme and prices were not as volatile as Alberta prices. The one notable exception is the increase in average MAPP-North price in August. This price increase could be a result of the blackout in the eastern US and Canada as the MAPP area may have been called on to supply electricity to the affected areas during the weeks after the blackout. On-peak Alberta prices have generally been higher relative to other markets, implying an opportunity to profit from importing energy into the province.

Off-peak prices in Alberta have remained strong compared to MAPP-North prices but were weaker (with the exception of July 2003) relative to both Mid-C and North-Path 15 prices. These price differentials support the export activity observed over the quarter.

Because neither BC nor Saskatchewan operate open markets, it is difficult to assess the economics of moving energy to and from these areas, although energy is often moved through BC and Saskatchewan to markets in the US. 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.

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 (to the Pacific Northwest and the Eastern US) 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. Daily index prices are used for this analysis and not actual trade prices, therefore the analysis should be considered only directional in nature. Note that energy that originated in or was delivered to BC or Saskatchewan (whichever the case may be) is not included in the analysis.

Figure 16 - Economic Use of the BC Tie Line

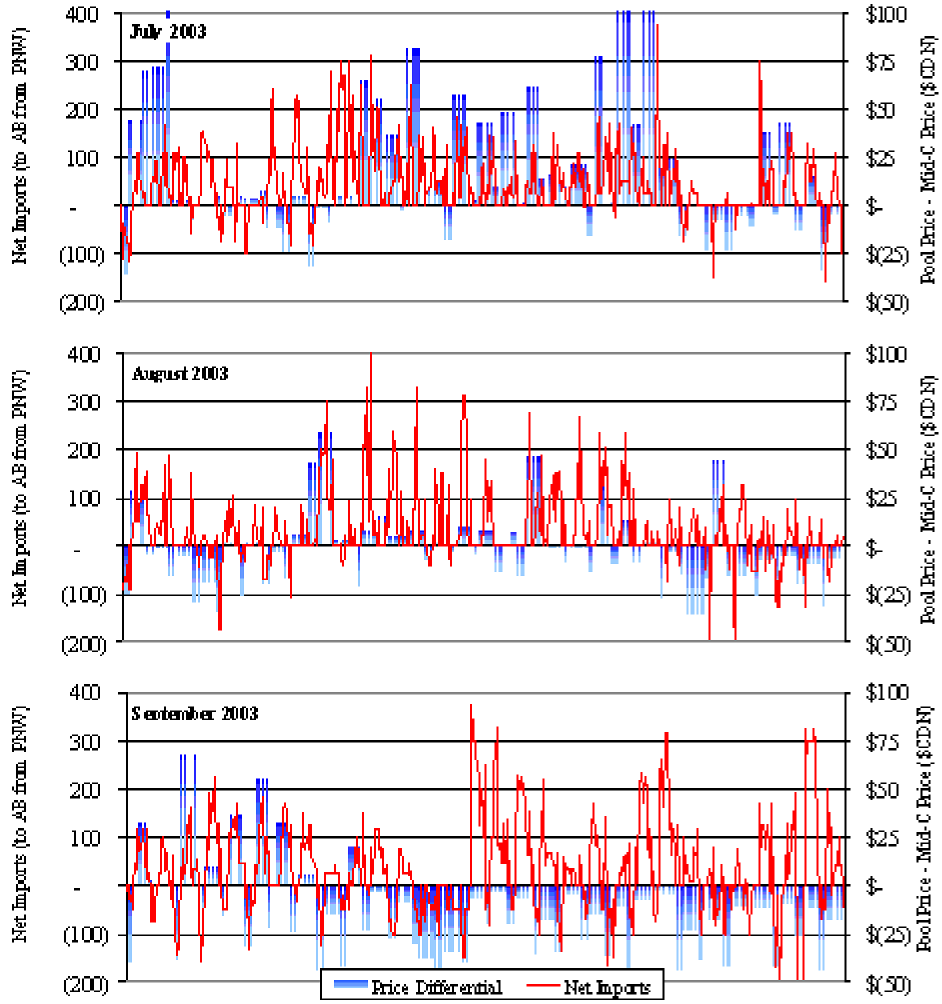


Figure 17 - Economic Use of the Saskatchewan Tie Line

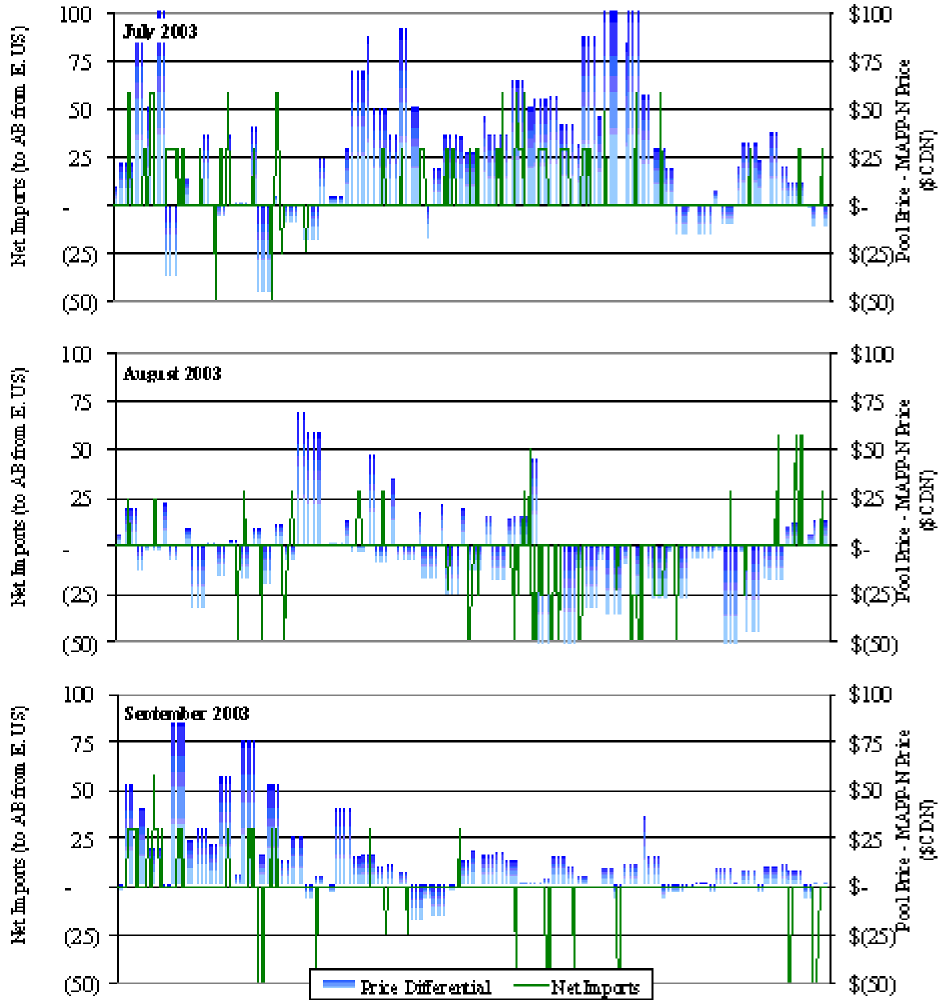


Figure 16 indicates that for the majority of the quarter, energy moving through BC was traveling in the right economic direction. Towards the end of September high volumes of imports from the Pacific Northwest during times when the price differential indicated that it would be more economic to export. Most of these imports occurred during the on-peak hours at times when the price differential was less than $10.00/MWh – generally less than the cost of transmission to the Pacific Northwest. This apparent inefficient use of the tie-line could possibly be the result of a "bad guess" on the part of the importer(s) or the result of his imports (which must be offered into the market at $0/MWh) depressing the Pool price for that hour. In some cases participants may be importing at an apparent loss to cover a short position caused by unexpected outages.

Figure 17 indicates that for the majority of the quarter, energy moving through Saskatchewan was traveling in the right economic direction. During September apparent exporting at a loss was observed on a number of occasions. These instances tended to be short in duration (one or two hours at a time) and usually occurred at times with fairly low price differentials.

During Q3/03 the MSA did not observe any inefficient import or export activity which it felt was untoward. However, the MSA continues to monitor the economic use of the tie-line and may approach a particular importer or exporter if prolonged or continually repeated economically inefficient use of the tie-lines is noticed.

1.10 Ancillary Services Market

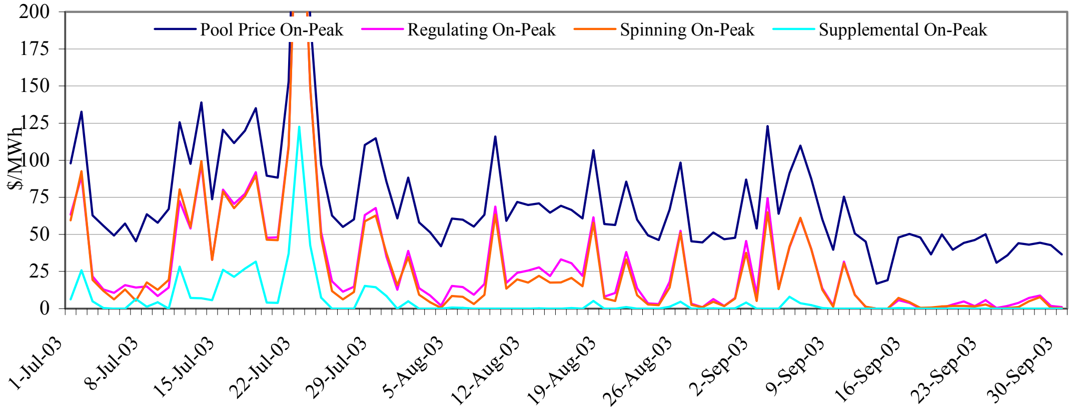
In the Q2/03 quarterly report, the MSA noted that a liability concern had been perceived by some market participants due to language in the new *Electric Utilities Act* (the "Act"). As a result of this concern, the AESO has made indemnification agreements available to ancillary services providers as an interim measure to relieve concerns while the AEUB takes the matter under consideration. A decision on the "liability module" is expected to be rendered by the AEUB by late Q4/03, although it is not known at this time what form a long-term solution to the liability issue will take based on the outcome of the AEUB decision.

Another development in the Ancillary Services market relates to current constraints that exist with respect to the combination of operating reserve services a qualified participant is able to provide concurrently as well as how frequently a participant can transact in the standby market for the same delivery date. The AESO has begun a broad based systems enhancement that will allow participants to provide both active and standby reserve services for the same reserve type at the same time, and from the same asset (ie: active spinning reserve and standby spinning reserve). As well, this change will enable participants to transact multiple times in the standby market for a given reserve service for the same delivery date and instrument (on-peak or off-peak). These enhancements are expected to be implemented by early Q2/04.

Looking at market metrics for Q3/03, **Figure 18** shows the clearing price of active ancillary service products traded on Watt-Ex through the quarter. **Table 4** shows the monthly averages of the daily values seen in **Figure 18**. As can be seen in the figure, on-peak clearing prices fell considerably toward the end of the quarter since on-peak Pool prices reached quarterly lows through this period and all active reserves are priced as a differential to Pool price. **Table 4** shows how the higher Pool prices in July flowed through as higher clearing prices in each of the traded products. The off-peak chart in **Figure 18** shows that off-peak clearing prices for the three reserve types tend to be clustered closer to pool price than on-peak clearing prices. This can be attributed largely to the more limited range of Pool prices that typically occur in off-peak periods.

Figure 18 - Ancillary Services Clearing Prices - Q3/03

Weighted Average (on-peak)



Weighted Average (off-peak)

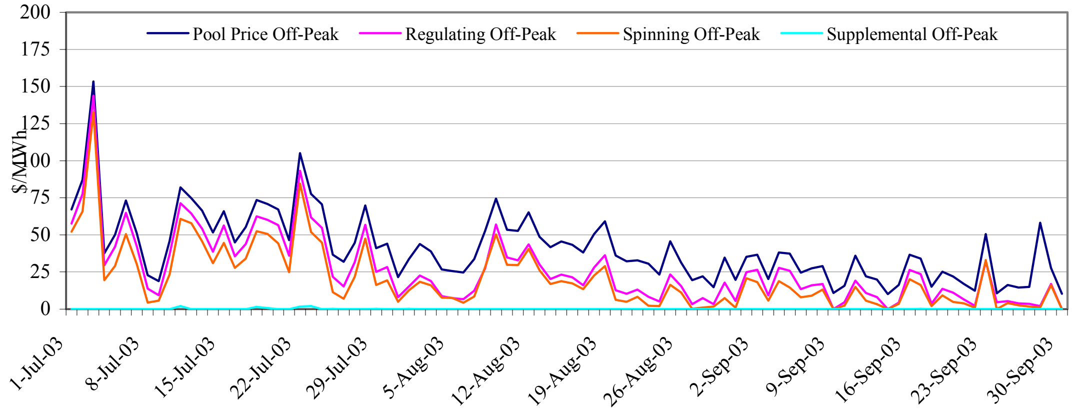
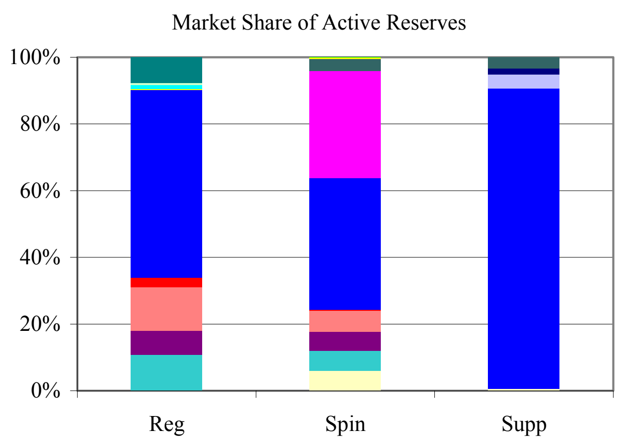


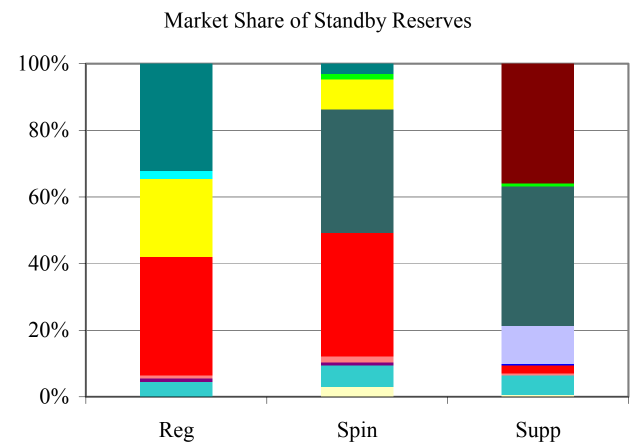
Table 4 - Monthly Average AS Clearing Prices; Q3/03 and Q2/03

	Active Clearing Prices (avg on-peak)			Active Clearing Prices (avg off-peak)		
Month	Reg	Spin	Supp	Reg	Spin	Supp
Apr	32.80	18.45	2.28	21.60	18.12	0.06
May	35.27	17.23	1.48	16.47	11.94	0.00
Jun	23.70	18.44	4.69	14.38	10.77	0.00
Q2/03	30.59	18.04	2.81	17.48	13.61	0.02
Jul	58.25	57.22	14.81	48.20	38.63	0.26
Aug	19.99	15.60	0.63	18.99	14.88	0.01
Sep	13.12	11.86	0.64	12.10	8.46	0.01
Q3/03	30.46	28.23	5.36	26.43	20.66	0.09

Figure 19 shows the (anonymous) breakdown of market share in the 6 competitively procured ancillary service markets in Q3/03. The colors denoting individual market participants are consistent between the chart showing active reserves and the chart showing standby reserves. The physical characteristics of generating assets (as well as load assets) tend to make certain assets better suited to provide either active or standby reserve services, which is why the two charts show a substantially different participant makeup.

Figure 19 - Ancillary Services Market Share – Q3/03





1.11 Forward Markets

Exchange traded forward activity in the Alberta market is split between the Alberta Watt-Exchange (Watt-Ex) and the Natural Gas Exchange (NGX). There is additional over-the-counter (OTC) activity among market participants and although there is some level of visibility into bid/offer spreads, the MSA has little visibility into volumes transacted on the OTC market.

In Q3/03, forward volumes on Watt-Ex, while still modest, increased to 286,985 MWh relative to 143,710 MWh in the previous quarter. Volumes traded on NGX since the introduction of its Alberta basis contracts in early Q2/02 increased marginally, although trade remains intermittent in these instruments.

New developments occurred on both Watt-Ex and on NGX during Q3/03 which should enhance the ability of market participants to transact in the forward energy markets. Watt-Ex has extended the availability to trade daily instruments from 7 days ahead to 30 days ahead. NGX has introduced additional fixed-for-floating electricity financial swap contracts with a Mid-C basis and has also added an extended peak contract to its Alberta basis contracts. Thus far, no trades have been observed in the Mid-C basis contracts since their introduction.

1.12 Outages and Derates

The MSA monitors the outages and derates of generating units in Alberta. Of particular interest are the previously regulated thermal generating units that are now operated under the terms and conditions of the Power Purchase Arrangements (PPAs). This is due to the design of the PPAs, where outages impact plants whose capacity and energy has been purchased by another party. Therefore, outages at these plants impact both the plant owners' portfolios and the PPA buyers' portfolios. Also, the PPA coal units are large compared with most peaking units and represent a major portion of installed capacity in Alberta (approximately 5500MW in total or about 50% of installed capacity). Therefore, outages at these units tend to have a significant impact on the Pool price.

The MSA monitors unit availability on a real-time basis, as well as having developed a number of data filters which indicate when the timing or duration of outages and derates deviates significantly from a unit's historical performance. When the amount of outage exceeds a unit specific threshold, a flag is raised and the MSA seeks to understand from the owner more about the causes leading to the situation. The MSA has also developed a number of metrics used to analyze outages and derates with respect to market conditions such as system demand, Pool price and the 30-day rolling average Pool price. As well, the MSA monitors the amount of planned outage versus unplanned outage and how this ratio changes over time.

Historically, outages and derates, both planned and unplanned, tend to fluctuate or appear cyclical on both a quarterly and annual basis. The amount of outage can vary from one time period to the next because planned outages are generally scheduled on a multi-year basis. This in turn impacts upon unplanned (maintenance and forced) outages. Also important to unit availability is the age of a generating unit. As with other machines, generating units generally require more frequent maintenance as they age.

The importance of the coal-fired PPA generating fleet to market outcomes is underscored by **Figure 20**. It illustrates that as unit availability increased from July through September from 85% to 95%, average monthly Pool price decreased from $87.91/MWh to $43.59/MWh. Average availability for the quarter, accounting for both planned and unplanned outages was 90%, with a corresponding average Pool price of $62.59/MWh. Note that this analysis excludes other factors that may impact on Pool price including changes to system demand, import/export activity and the price of natural gas. Regardless, the relationship between coal-fired availability and Pool price is strong.

Figure 20 - Coal-Fired MW Weighted Avg Availability and Pool Price

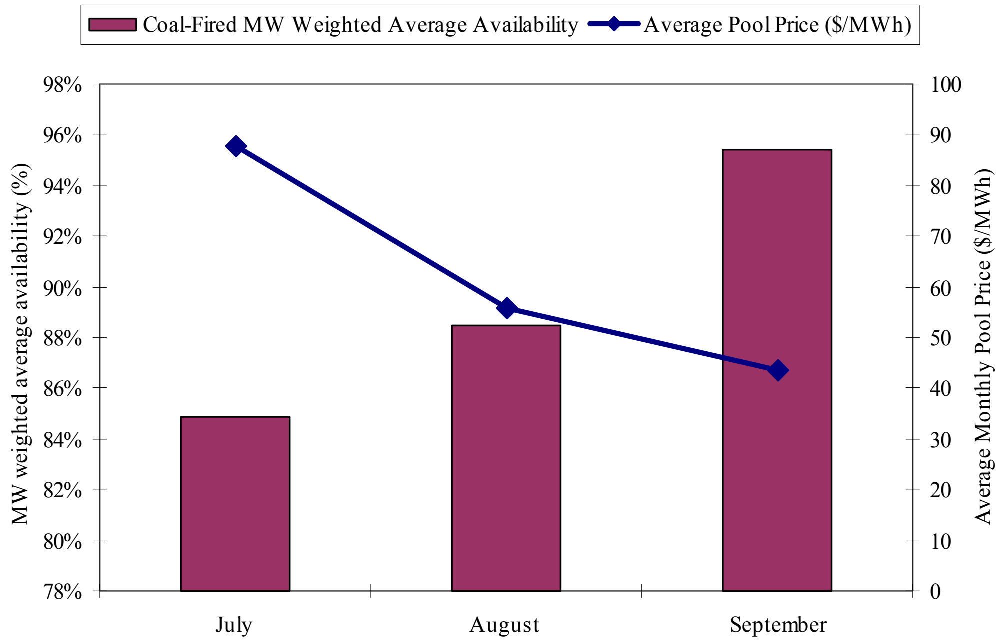


Figure 21 illustrates planned and unplanned outage levels for 2001, 2002, and January through September 2003. The figure illustrates that the overall PPA outage level at the coal-fired facilities has been relatively stable from 2001 through September 2003. However, there have been fluctuations at the owner level. The graph illustrates outage levels for the three PPA owners (referenced as *Owner A, B* and *C*). *Owner-A's* outage level has cycled from 5.6% in 2001, up to 8.1% in 2002 and down slightly to 7.4% for January to September, 2003[1]. *Owner-B's* coal fired PPA outage level has also shown some variability, from 5.4% in 2001 to 2.9% in 2002 and up to 4.1% for year-to-date 2003. *Owner-C* saw its overall PPA coal outage level range from 14.2% in 2001 to 13.1% in 2002 and 13.5% in the first 3 quarters of 2003.

The first three quarters of 2003 saw a higher rate of planned outages as a percentage of total outages than was experienced during 2002. Again, variations are expected on a year-over-year basis due to multi-year planned outage cycles. In 2002, the planned outage rate was 2.7%, which represented only 26% of all outages. Year-to-date 2003 has seen a planned outage level of 7%, which represent about 50% of all outages.

[1] Outage levels are weighted based on the maximum continuous rating (MCR) of each unit in the Owners' portfolios.

It should be noted that although outages have traditionally been considered either planned, forced or maintenance, the definitions can be somewhat arbitrary. Planned outages are normally scheduled in conjunction with the AESO, and are known well in advance. Forced outages are imminent or immediate outages with little scheduling flexibility. Maintenance outages are similar to forced outages, except that they are able to be delayed up to the start of next planned outage. The definitions between maintenance and planned outages can become administratively blurred when planned outages are rescheduled, which can lead to a previously planned outage being recorded as a maintenance outage (unplanned).

Figure 21 - Planned and Unplanned Outage - PPA Coal-Fired Units

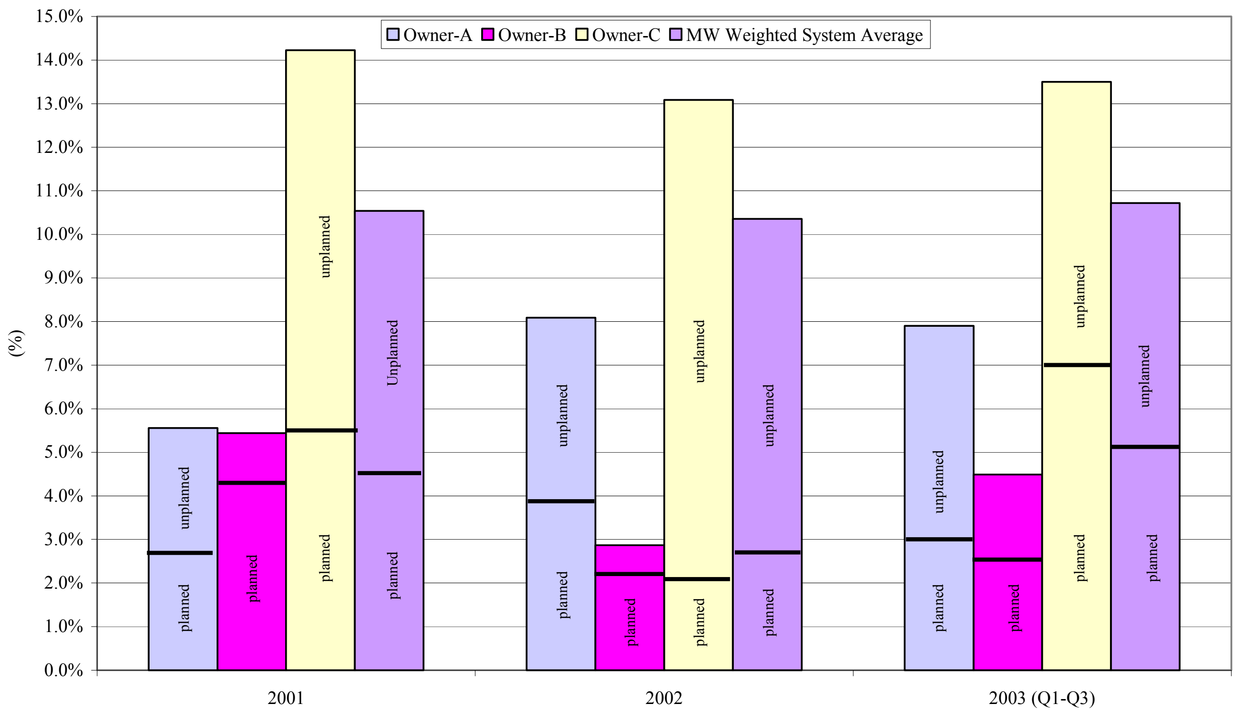


Table 5 reports unplanned outages on a quarterly basis for 2003, the 2003 year-to-date average, as well as 2002 and 2001 annual averages. On a quarterly basis, overall MW weighted average unplanned outages (the number of MWh's lost to forced and maintenance outage by the PPA coal units) in Q3/03 varied by owner when compared to Q2/03. Overall Q1/03 unplanned outage was 4.6%, Q2/03 was 4.7% and Q3/03 was up at 6.0%. Year to date, unplanned outages are below both 2002 and 2001 levels. This is consistent with the fact that there has been a higher rate of planned

outages during the first 3 quarters of 2003. Two of the plant owners experienced higher unplanned outage rates in Q3/03 than in Q2/03. One of the owner's unplanned outage rate is down slightly over Q2/03, by 0.1%.

Table 5 – Outage for PPA Coal Units (% excluding planned outages)

	Q3/03	Q2/03	Q1/03	2003 YTD	2002	2001
Owner-A	6.3%	1.4%	3.7%	4.4%	4.2%	2.8%
Owner-B	2.4%	2.1%	1.1%	1.9%	0.5%	1.2%
Owner-C	6.7%	6.8%	6.0%	6.5%	10.8%	8.8%
PPA weighted average	6.0%	4.6%	4.7%	5.3%	7.7%	6.0%

Note: 1) PPA units include: Genesee 1 & 2, Battle River 4, 5, 6, Sherness 1 & 2, Wabamun 1, 2, 3 [up to Nov 28 2002], 4, Sundance 1 - 6, Keephills 1 & 2. 2) Outages rates are based on maximum continous rating (MCR), not gross unit capacity.

The design of the PPAs stipulates target availabilities for each PPA covered unit, based on historical performance and factors such as a unit's age and design. By owner, **Table 6** reports the MW weighted average target availability for each PPA coal fired portfolio and the actual availability achieved during the first 3 quarters of 2003 [2]. On average, the PPA owners have reported higher actual availability than target availability.

[2]Actual availability in the PPAs is defined as the minimum of the declared availability or committed capacity, whichever is less. The actual availability reported here is not calculated using availability declarations, but is instead calculated using data provided by the PPA owners.

Table 6 – MW Weighted Portfolio Target Availability (%) vs. Actual Availability – Coal Fired PPA Units

	Target Availability 2001	Actual Availability 2001	Target Availability 2002	Actual Availability 2002	Target Availability 2003	Actual Availability 2003 YTD
Owner-A	88%	94%	88%	92%	87%	92%
Owner-B	90%	95%	90%	97%	90%	96%
Owner-C	86%	86%	85%	87%	85%	86%

In terms of overall availability, and compared with historical trends, Alberta's PPA units have performed well over the 3 quarters of 2003. The cycle of fewer planned outages as compared to unplanned outages that was seen last year has trended back up, with more planned outages being recorded so far this year.

2 REVIEW OF THE RETAIL MARKET

2.1 Regulatory Proceedings

The MSA has continued its regular watch of proceedings before the Alberta Energy and Utilities Board (AEUB) and the British Columbia Utilities Commission (BCUC). The MSA intervened in certain applications before the AEUB and BCUC, for reason that they may significantly impact the mandate of the MSA. However, the MSA has not taken an active role in any related hearings.

The MSA and the AEUB are handling a joint application received from ATCO Electric and ATCO Gas for an exemption under each of the *Code of Conduct* regulations. The two regulations are very similar in nature and content; one relates to the *Gas Utilities Act* and the other to the *Electric Utilities Act*. The application is made to the AEUB pursuant to section 41(1)(a) of the (gas) *Code of Conduct Regulation*, and to the MSA pursuant to section 43(1)(a) of the (electric) *Code of Conduct Regulation*.

The exemptions sought would allow those entities to share certain customer information with Direct Energy Marketing Limited and Direct Energy Partnership in advance of the closing of the proposed sale of the ATCO retail electricity and gas businesses. The MSA and AEUB have established a process whereby a joint record is developed and maintained; however, the decision of each regulator will be handled independently, though based upon the joint record.

The application materials and the related Notice of Application are available on the MSA website at http://www.albertamsa.ca.

2.2 Settlement System Code Monitoring & Enforcement

The AESO brought forward its proposed changes to the Settlement System Code in August, 2003, and made changes in the related AESO rules effective September 30, 2003. The specific changes and related materials can be seen on the AESO website (http://www.aeso.ca) and are discussed elsewhere in this report under **New AESO Rules**.

The MSA will be monitoring the effect of the rule changes around Load Settlement Compliance Enforcement, as part of its overall surveillance responsibilities under the Act.

2.3 Code of Conduct Regulation

In accordance with its responsibilities under the Code of Conduct Regulation (Code), the MSA has begun a series of meetings with stakeholders in preparation for the reviews and approvals which will be required before the end of 2003. Those include approval of compliance plans for certain owners and affiliated retailers. Discussions around audit plans are also ongoing, in preparation for Code audits which will be required for certain parties in 2004.

Also in respect of the Code, the MSA issued a letter to certain parties in September, 2003 setting out its views around the manner of customer consent required for disclosure and use of customer information. In essence, the MSA considers that written or electronic consent would be the standard required under the Code, and would expect that to be addressed in the compliance plans of the various parties subject to the Code.

The letter was intended to clarify any uncertainty amongst market participants in this regard. In particular, the MSA was aware of concerns around use of so called 'negative option' consent practices, wherein notice would be given to the customer that their consent to disclosure and use of their information would be considered given unless the customer indicated that they were in fact not consenting.

The MSA is participating in the ongoing discussions amongst market participants, the government and other stakeholders in respect of these matters.

2.4 Mystery Shopper

When considering the development of the retail market in Alberta, progress has generally been good for large and medium size customers. The mass market, that is, residential customers, has been slower to embrace Customer Choice. Switching statistics clearly indicate that most residential customers are still on Regulated Default Supply (RDS, formerly Regulated Rate Option).

There are various reasons why residential customers may not yet have elected to choose among the competitive offerings by retailers. Simple inertia may explain this in large measure since the default supply option is the easiest for us since we do not actually have to do anything for it to happen. The notion that the retail service does not necessarily have to be provided by the same entity that owns the physical connection to the home is still not yet fully understood by all Albertans in terms of electricity service although the concept seems to be understood in terms of other services – long distance telephone service for example. In some cases, people have actually assessed the choices and elected to remain on RDS, but this is likely a small proportion.

Through migration and having a younger population, Alberta would appear to have potentially many new electricity customers each year and it is of interest whether these new customers receive helpful information when they contact the 'Electricity company' looking for service. When these potential/actual new customers contact the wires companies looking for service, are the customers well served in terms of helping them to understand the available choices or does the system gently lead them toward RDS? The Code of Conduct Regulation (Code) covers many aspects of the way in which the wires companies and their affiliated retailers are obligated to behave. For example, if a person calls the wires company, it is not supposed to promote its affiliated retailer, or to treat retailers differently. The MSA is responsible for overseeing compliance to this Code. Our interest here was to assess how the wires companies are doing in terms of helping new customers understand the Alberta situation with respect to electricity. Compliance with the Code was not the focus of this exercise.

Assessment Approach

The MSA contracted with an outside firm to conduct a "mystery shopper" type survey. Their researchers contacted the various wires companies call centres posing as potential new customers and gauged the call centre responses. The purpose of the survey was simply to assess whether the call centres of the wires companies, the logical first point of contact for potential new customers, was helpful to the callers in terms of describing their options in the deregulated market. This exercise did not attempt to design a statistically robust scheme, and accordingly, the findings must be considered in the same way.

Survey Details and Findings

There are call centres for four wires service providers in Alberta: Aquila Networks, ATCO Electric, Enmax and EPCOR. The two scenarios that were tested for each call centre were:

Potential new resident of Alberta: 'Hi, I might be moving to XXX into a new house and would need to arrange for hydro. What is the process? ' (with some variations).

Potential customer to switch from RDS, 'Hi, I am confused. What's with these ads I see from XXX (Enmax, EPCOR or Direct)? Do they have wires in my area so I can buy electricity from them?' (with some variations)

Each scenario was sampled 25 times with each of the four call centres for a total of 200 calls. The survey was done over a three week period in September, randomly spread out to prevent the centres from becoming suspicious of a large number of similar calls. The callers had a template sheet to check off various aspects of the call centre staff responses. They also took brief notes of overall impressions. The type of work leads to all kinds of statistics which were recorded and assessed by the research company – only the overall impressions will be mentioned here recognizing the objectives of the work.

Researchers found no overall trend by call centre agents to regularly refer to the affiliated retailer, in the course of an inquiry. In the 200 calls made 32 references to the affiliated retailer were recorded. While this number appears to be significant it must be seen in context with the types of inquiries made and how the agent used the name of the affiliated retailer in the conversation. In most cases, the name of the affiliated retailer was used along with the name of an unaffiliated retailer or as an example to explain to the caller the distinction between the wires service side of the company and the retail side.

There were a few isolated cases where the call centre agent mentioned to the researcher that if they wanted immediate electricity service it could be arranged through the affiliated retailer. Even in those situations the agent made it clear that the caller had a choice of retailers. He or she was only suggesting this action as it might take an unaffiliated retailer longer time to register the new account with the wires company, than if he or she made the arrangements now over the phone. The agent pointed out that later the caller could change retailers.

The more significant information is the number of times researchers were directed to the Customer Choice web site and given the Customer Choice toll-free phone number to get a list of retailers. In almost all of the inquiries made by researchers, they were told that the agent could not give them the name or names of the retailers but that they could get a list from the Customer Choice web site or by calling for the list. This information is considered significant.

Conclusion

The study revealed that overall, with few exceptions, calls were received and addressed by the wires company's call centre agents in a very professional manner. The call centre staff provided the kinds of responses that were helpful to the mystery shoppers seeking to understand what their options were.

Few signs of bias towards affiliated or unaffiliated retailers were detected. The majority of call centre agents steered clear of recommending a retailer and in most cases either directed the caller to the Alberta government's Customer Choice web site address or toll-free phone number. There were a few isolated situations where the call centre agent was terse with the researcher, appeared to be unfamiliar with the new market framework, and either forgot or neglected to give out the government's web site or toll-free phone number.

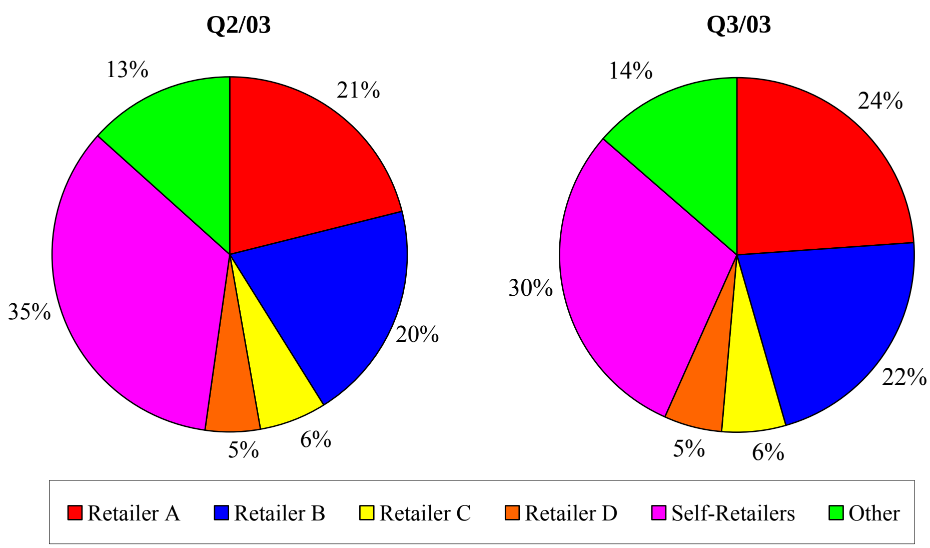
2.5 Retail Market Metrics

In the Q2/03 quarterly report the MSA started reporting a series of retail market metrics including:

- Number of active retailers
- Retailer entry and exit from the market
- Market share (with respect to load) of retailers by customer class
- Customer switching off the regulated rate option to a competitive contract by RRO[3] eligible customer class.

As of September 30, 2003 there were 103 active retailers in the Alberta electricity market, 74 of which are self-retailers. This is an overall decrease of 2 retailers since the end of Q2/03 and an overall increase of 3 retailers since the end of 2002. Although the total number of retailers has decreased, 2 new retailers have entered the market since June 30, 2003. This level of retailer entry and exit from the market appears to indicate a fairly healthy level of competition given the size of the market.

Figure 22 – Overall Market Share of Retailers

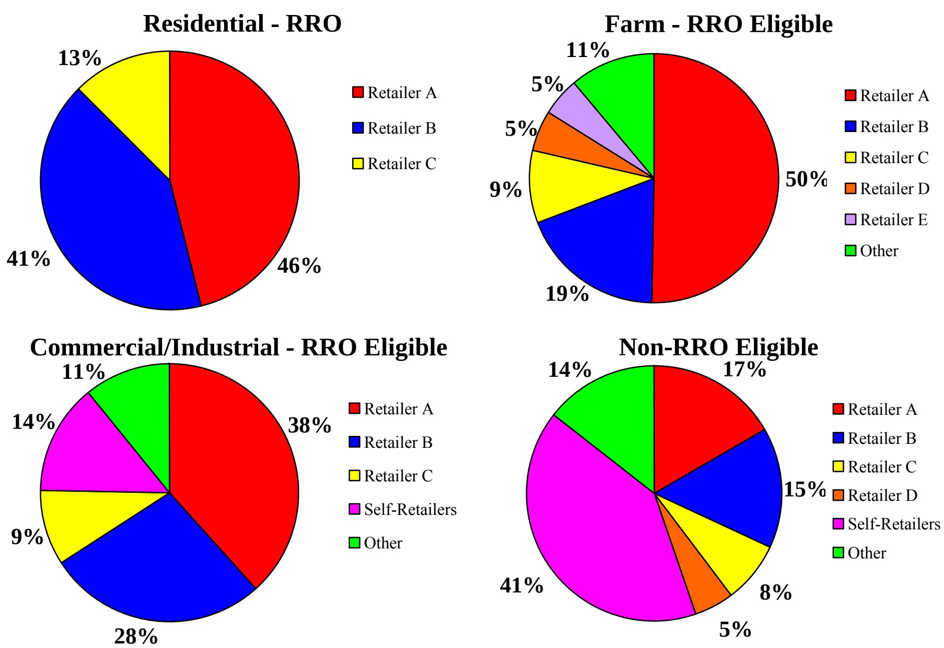


Note: Retailer labels do not necessarily represent the same retailer for each quarter.

[3] As discussed in the new EUA, RRO is now termed regulated default supply.

Figure 22 shows the overall (all classes) market share of retailers for Q3/03 compared to Q2/03. The figure shows that there are four retailers in the province with market shares (by load) of at least 5%. Since the end of Q2/03 the market share of the four most prominent retailers has actually increased from 52% to 57%, with most loads moving away from the self-retail category to one of the two largest retailers. The market share of self-retailers has decreased from 35% to 30%. Note that these market shares are based on loads and not number of customers. The overall load was approximately 11% higher in Q2/03 than in Q3/03. This could indicate that the more seasonally variable loads have opted to self-retail. Overall the figure indicates movement of load between the various retailers. This is viewed as a sign of healthy competition.

Figure 23 – Q3/03 Market Share of Retailers by Customer Class



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

Table 7 - Progression of Retailer Market Shares

Customer Class	Retailer						
	A	B	C	D	E	Self	Other
Q2/03							
Residential	45%	42%	13%	n/a	n/a	n/a	n/a
Farm	41%	35%	6%	6%	n/a	n/a	12%
Commercial/Industrial	38%	25%	10%	n/a	n/a	16%	11%
Non-RRO Eligible	16%	13%	8%	n/a	n/a	46%	18%
Q3/03							
Residential	46%	41%	13%	n/a	n/a	n/a	n/a
Farm	50%	19%	9%	5%	5%	n/a	11%
Commercial/Industrial	38%	28%	9%	n/a	n/a	14%	11%
Non-RRO Eligible	17%	15%	8%	5%	n/a	41%	14%

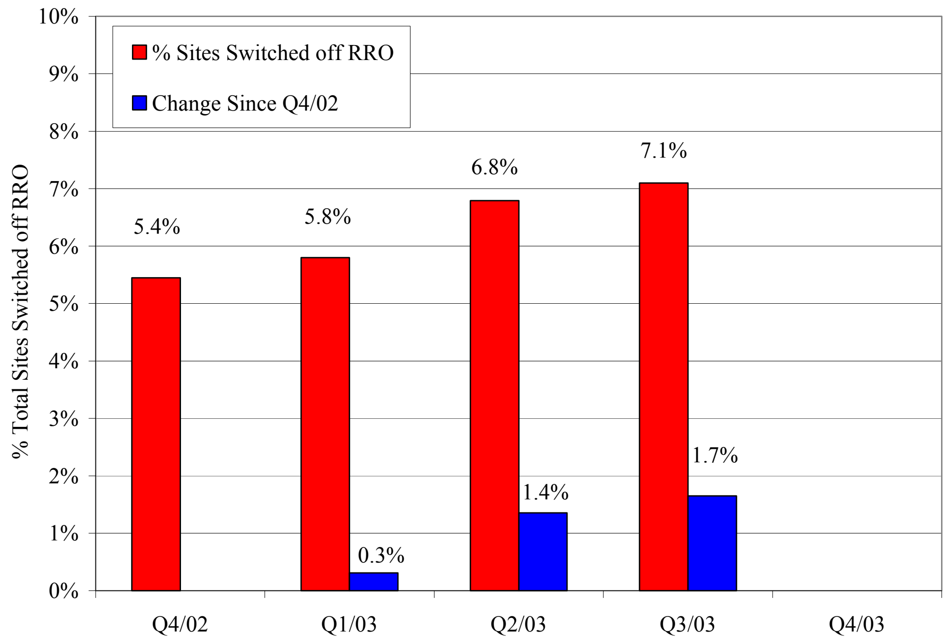
Figure 23 shows retailer market share by customer class for Q3/03. **Table 7** shows retailer market shares by customer class for the last two quarters. Note that retailer labels do not necessarily represent the same retailer in each category or each quarter.

In the Residential – RRO Eligible and Commercial/Industrial – RRO Eligible classes, load distribution amongst retailers has remained fairly static since Q2/02. These statistics are not surprising for the residential class because at this time there are essentially only three retailer options for residential customers. The results are somewhat more surprising for the small commercial class. At the end of 2003, the regulated rate option expires for small commercial customers. At that time, small commercial customers will either have to choose a competitive contract from a retailer or will be moved onto a flow-through regulated rate offered by their existing RRO provider – much like the flow-through rate already in place in the ATCO service territory. We would expect an increase in market share values in the self-retailer and other categories, indicating the movement of loads away from the incumbent retailers, yet this does not appear to be the case. Switching of customers in this customer class will be discussed later in this section.

Market share statistics for the Farm – RRO Eligible and the Non-RRO Eligible classes show a reasonable change in distribution of loads amongst the retailers. In both classes one additional retailer has achieved a market share of at least 5%, increasing the number of retailers with a market share of at least 5% to five and four in the farm and non-RRO eligible classes respectively. The movement of loads to other retailers is encouraging. However, it appears that some load has migrated from the self-retail and other categories towards the incumbent retailers.

The overall progression of customers off of RRO rates to competitive electricity contracts continues to move in the right direction. As of September 30, 2003, 7.1% of all RRO eligible customers have chosen to sign a competitive contract with a retailer, as shown in **Figure 24**. This represents a 1.7% increase since the end of Q4/02 and a 0.3% increase since the end of Q2/03.

Figure 24 - Progression of RRO Eligible Sites Switching Off RRO



Note that these switching statistics do not reflect what was reported in the MSA's Q2/03 Quarterly Report as one Load Settlement Agent (LSA) has changed its reporting procedures for this metric. In previous reporting, this LSA reported switching statistics on both active and inactive sites. As a result, switching statistics were artificially low for this LSA. The procedure has now been changed and the LSA in question reports numbers that reflect only active sites – an approach that is more consistent with the approaches taken by other LSAs. The effect of this reporting change was an increase in overall switching rates throughout the reporting period – particularly in the farm class. **Table 8** shows the revised progression of RRO eligible sites switching off RRO for the last four quarters by customer type.

Table 8 - Progression of RRO Eligible Sites Switching off RRO

	% Customers NOT on RRO			
	Residential RRO Eligible	**Farm RRO Eligible**	**Commercial/ Industrial RRO Eligible**	**Overall**
Q4/02	1.8 %	9.7 %	24.2 %	5.4 %
Q1/03	2.5 %	9.8 %	22.6 %	5.8 %
Q2/03	3.3 %	9.9 %	25.6 %	6.8 %
Q3/03	3.6 %	9.9 %	26.2 %	7.1 %

The number of sites switching off RRO has increased in every category (although only very marginally in the farm class) for Q3/03. Although the progression is quite slow, it shows that the Alberta population is becoming more accepting of the idea of a competitive electricity market.

The progression of Commercial/Industrial – RRO Eligible customers off of RRO is not as high as might be expected considering the impending expiration of the regulated rate option. Only 0.6% of RRO customers (representing just over 2,000 sites) signed competitive contracts in Q3/03. The MSA will be watching switching rates in this particular category quite closely as RRO eligible small commercial customers are forced to choose between a competitive contract and a flow-through rate for electricity.

3 MARKET ISSUES

3.1 Information Sharing Issues

The sharing of confidential information within organizations and between market participants is contemplated by the nature of the market and the industry. It is part of doing business. However, from a market perspective, "information sharing" issues may arise (that is, the potential for inappropriate sharing and use of confidential information). Thus, to the extent that information flows and information asymmetry can affect the fair, efficient and openly competitive operation of the market, effort is required to limit inappropriate information sharing.

Existing business structures such as the power purchase arrangements, agency relationships and joint ventures are obvious examples of commercial arrangements within which confidential commercial information must flow on a regular basis. Further, the MSA has seen a rise in the number of innovative business arrangements being contemplated and brought forward by market participants, and sees this as a positive occurrence for the market.

Given that such arrangements are integral to the operation of the market, the MSA is of the view that measures undertaken to address any information sharing issue must not only address the targeted behaviour but must also take into account goals such as facilitation of the market, costs of monitoring and compliance, and other practical and policy considerations.

In order to obtain feedback on the issues, and on measures which might be available to address any concerns around information sharing, the MSA undertook a series of workshops and other meetings during April and May. These workshops generated considerable discussion amongst the parties, and were well received in general. The MSA has assimilated all the information from these workshops along with other inputs which it sought. During this time, the MSA is preparing material for discussion first with the policy makers, then with the workshop participants, and ultimately with the market at large. This is a complex issue and as such, the MSA is finding that it will take longer to bring recommendations forward than originally anticipated.

3.2 Outage and Derate Study

The MSA has undertaken a project to analyze outages and derates at coal fired generating plants covered under the Power Purchase Arrangements (PPAs) in Alberta. The analysis focuses on PPA coal plants for a number of reasons. First, due to the design of the PPAs, outages impact plants whose capacity and energy has been purchased by another party.

Therefore, outages at these plants impact both the plant Owners' portfolios and the PPA Buyers' portfolios. Second, the PPA coal units are large compared with most peaking units and represent a major portion of installed capacity in Alberta (~5500MW or 50% of installed capacity). Therefore, outages at these units tend to have a significant impact on the Pool price. Third, the size of the portfolios in which the PPA units are held potentially position the Owners to benefit from strategically timing outages, both in terms of the 30-day rolling average Pool price (based on an incentive built into the PPA) and from their remaining portfolio position in the market. Therefore, the coal units covered under the PPAs represent a unique situation in the Alberta market.

The *Outage and Derate Study* has been undertaken with the view that a systematic approach, using analytical techniques such as regression analysis, should be developed to augment the real time monitoring and statistical filters already used by the MSA to examine coal unit availability. The intention is to generate a better understanding of coal unit availability in Alberta, as well as to develop a process to diagnose potential market issues such as physical withholding or manipulation of outages that could impact negatively on the efficient and openly competitive operation of the market at large.

Four metrics based on regression analysis were developed to examine unit availability. They are: 1) a regression of daily average outage (excluding planned outages) versus day-ahead average forecast demand; 2) Unit outage versus the supply cushion; 3) Specific portfolio outage against PPA system outage (excluding the specific portfolio outage); and 4) A regression of outage against the 30-day rolling average Pool price. The fourth metric addresses a specific industry issue regarding the PPAs, concerning the timing of planned outages around the 30-day rolling average Pool price.

Unplanned Outage and Day Ahead Forecast Demand

The first indicator is a regression of daily average unplanned outage versus day-ahead average forecast demand. It is simply a measure of whether, on average and over a specified time-frame, a portfolio tends to be available at times of higher forecast demand. In the absence of market power and to the extent operationally possible, it is economically rational for suppliers to be available to produce energy at times when forecast demand (and by association, expected price) is highest. If generators appear to be systematically absent from the market due to unplanned outage when forecast demand is highest, leading to a positive regression coefficient, this may indicate that the generator is physically withholding energy from the market in order to create higher spot prices.

Figure 25 presents the aggregate results of this analysis for 2002. The results for all metrics presented have been aggregated to ensure the confidentiality of individual PPA Owners. In the MSA's internal study, results were disaggregated by Owner. Each point in the figure represents the daily average amount of outage that occurred in each portfolio arising from the PPA units. As is clearly evident in **Figure 25**, there is a wide range of outage levels dispersed over the range of forecast demand. The trend line indicates a positive relationship between unplanned outages and forecast demand. As mentioned, our expectation was one of either no relationship (a flat slope), or a negative relationship. On a disaggregate level, this result is being driven by a single Owner's outages.

Because of this anomalous result, the MSA investigated the outages in question to understand what was driving this dynamic, and expanded the analysis to include 2003 year-to-date to identify whether a longer-term systematic relationship existed. **Figure 26** reports the results of the same analysis for the first three quarters of 2003.

For 2003 year-to-date, this relationship has reversed itself both on an aggregate basis, and at the Owner level. The MSA will continue to monitor this relationship through Q4/03, as system demand is normally higher during this time of the year due to colder weather and because of increased demand associated with the Christmas season.

Figure 25 – 2002 Unplanned Outage vs. Day-Ahead Forecast System Demand

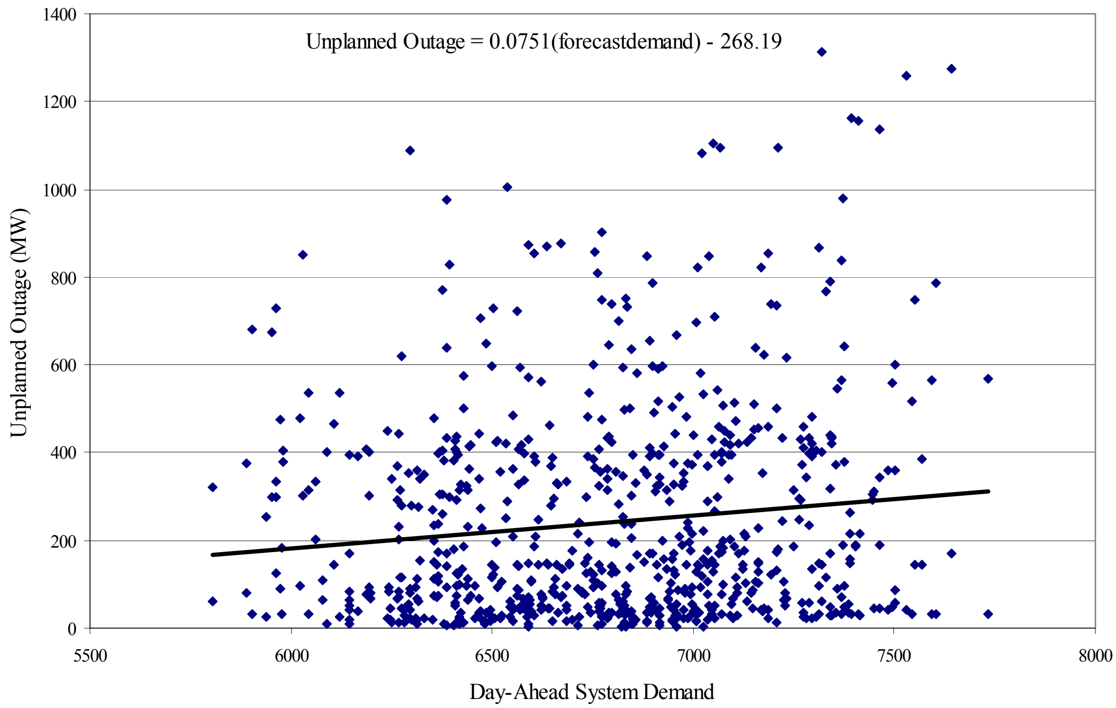
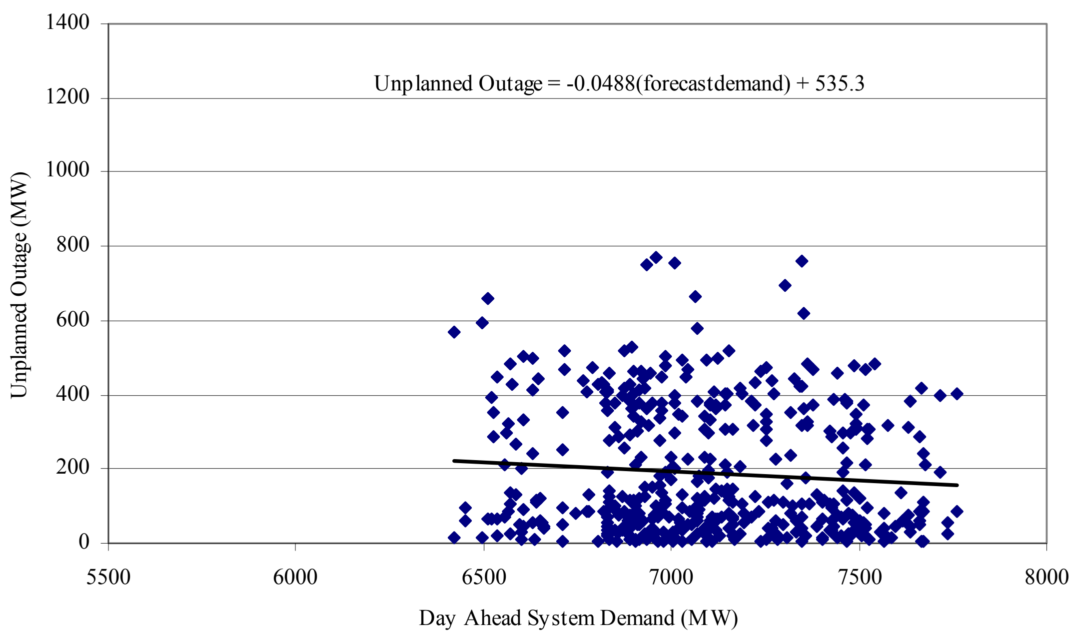


Figure 26 - 2003 (End of Q3) Unplanned Outage vs. Day Ahead Forecast System Demand



Unplanned Outage Versus the Supply Cushion

The second indicator analyzes portfolio outages against the supply cushion. The supply cushion is a measure of what capacity is available to the market, but not dispatched in a given hour. Again, presented herein are aggregate results for the PPA Owners. Each point represents the daily average unplanned outage that occurred in a given PPA coal unit Owner's portfolio during 2002. If a portfolio appears to systematically have lower availability when the supply cushion is tight, as compared with the other portfolios in the system, then further analysis of the owner's market behavior and associated unit specific market behavior (where applicable) may need to be analyzed.

Figure 27 shows that for the PPA units in 2002, there is a negative relationship between unplanned outages and the supply cushion. This is the expected direction of this relationship, because as overall outage increases, the supply cushion will, by definition, become smaller. What is interesting in this analysis is that on a disaggregate level, the slopes vary significantly among Owners. This suggests that some Owners tend to take more outages when the supply cushion is tight compared with other Owners.

Figure 27 - 2002 Unplanned Outage vs. Supply Cushion

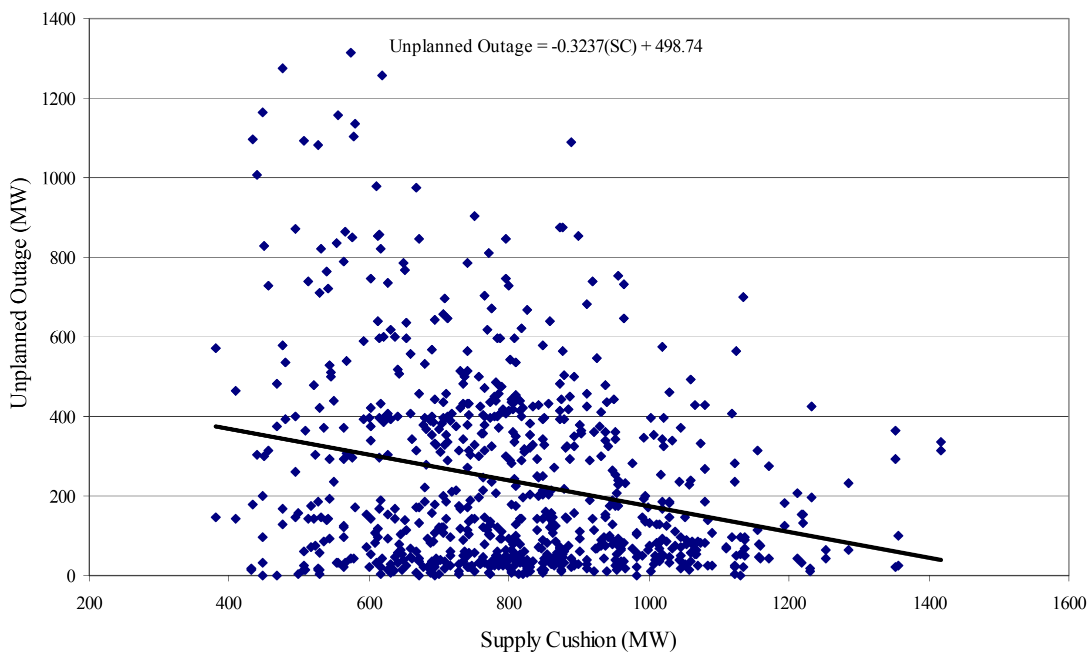
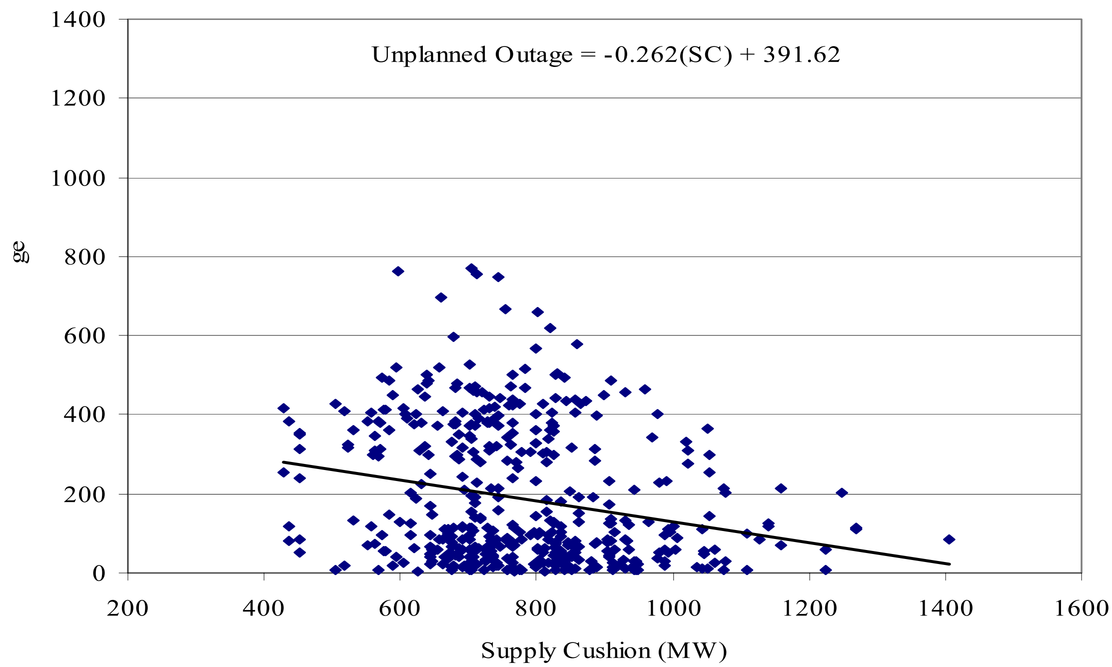


Figure 28 illustrates this relationship for 2003 year-to-date. In 2003 the slope of the relationship is less negative than in 2002. Significant differences remain amongst the individual Owners' portfolios however.

The flattening of the trend is due in large part to the fact that 2003 has experienced fewer incidents where multiple outages within the same portfolio have lead to a daily average portfolio outage level greater than 800 MW (approximately 2 large units). This high level of outage occurred on more than 30 occasions in 2002 but is yet to occur in 2003. Moving forward, the MSA will continue analyzing the difference in behavior between the Owners and changes over time in order to better understand the relationships.

Figure 28 - 2003 (End of Q3) Unplanned Outage vs. Supply Cushion



Portfolio Specific Outages Versus Overall PPA Outages

The third metric correlates individual Owner portfolio outages against outages occurring in the remaining portfolios. It is a measure of how each PPA Owner reacts to outages occurring at other Owners' units. If certain Owners appear to have systematically lower availability at times when other system outages are high, this will indicate that further analysis may be necessary.

This metric cannot be aggregated to maintain owner confidentiality. However, when the analysis was performed on an Owner-by-Owner basis, the results did not suggest there were systematic relationships between outages in one Owners portfolio compared to outages occurring in the other Owners' portfolios during 2002 – Q3/2003.

Planned Outages Versus the 30-Day Rolling Average Pool Price

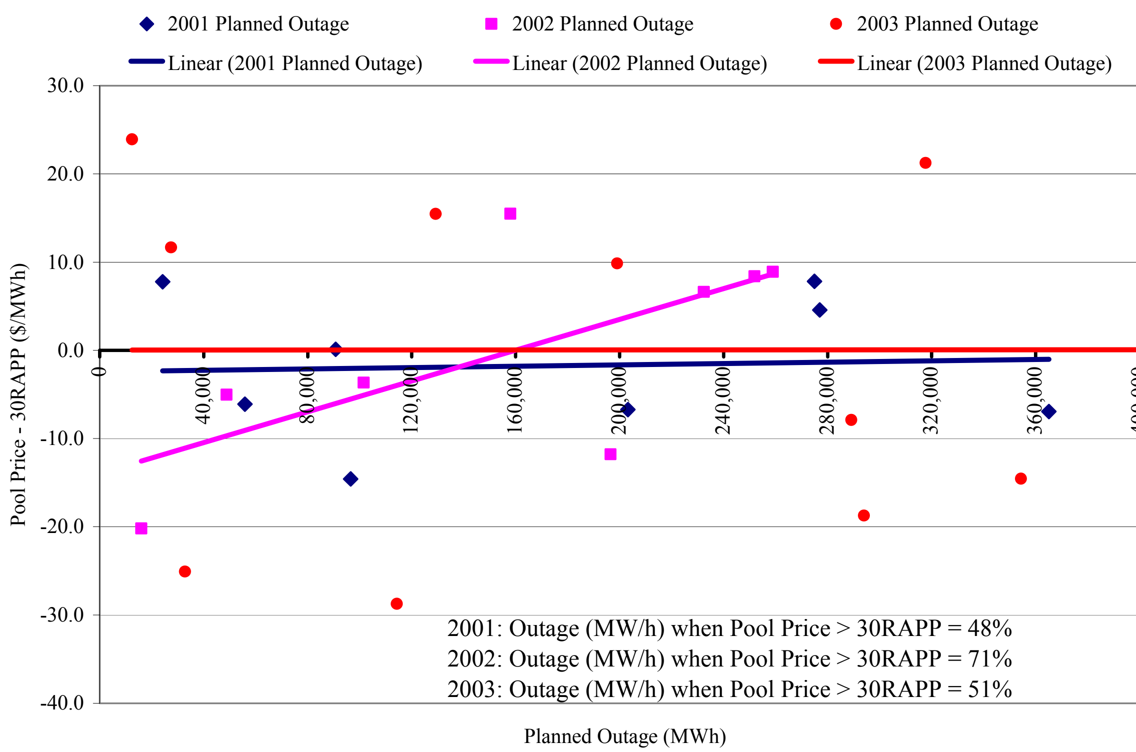
The fourth indicator is a comparison of planned unit outages and the 30-day rolling average Pool price (30RAPP). It is designed to examine whether generation Owners are scheduling their outages around times when the 30RAPP is lowest. There has been some suggestion by market participants that this is occurring, although *prima facie*, this does not constitute inappropriate market behavior. Rather it reflects the structure of the incentive payment component of the PPA.

Owners are incented to schedule outages when the 30RAPP is lowest due to the incentive payment system built into the PPA. The incentive payment system is based on the "Target Availability" of each unit. Target Availability is a standard based on the Committed Capacity of each PPA unit, the historical performance of each unit, as well as design, type, fuel and age of each unit (plus other factors). The availability incentive enables Owners to receive additional payments where the level of availability it achieves ("Actual Availability") is higher than the target. The Owner makes a payment to the Buyer when the actual level is lower than the target, and vice versa. Availability is calculated on an hourly basis using a rolling account concept. In hours when actual availability exceeds target availability, the account is drawn up. In hours when actual availability is below target availability, the account is drawn down. Payments in either direction are calculated based on the 30RAPP, less the Availability Energy Payment (AEP) component of the PPA. In the long run, if the performance of the units matches the target availabilities, the account should converge towards zero.

Figure 29 illustrates that the Owners were more successful at scheduling outages when the Pool price was greater than the 30RAPP in 2002 than in 2001. In 2003 the trend has shifted somewhat back to the trend seen in 2001. In 2003 the PPA Owners have scheduled half of the planned outages when the Pool price was greater than the 30RAPP, and half when it was less. This is down from 2002, when 70% of outages were scheduled when the Pool price was greater than the 30RAPP. In 2001, 48% of planned outages were scheduled when the Pool price was greater than the 30RAPP.

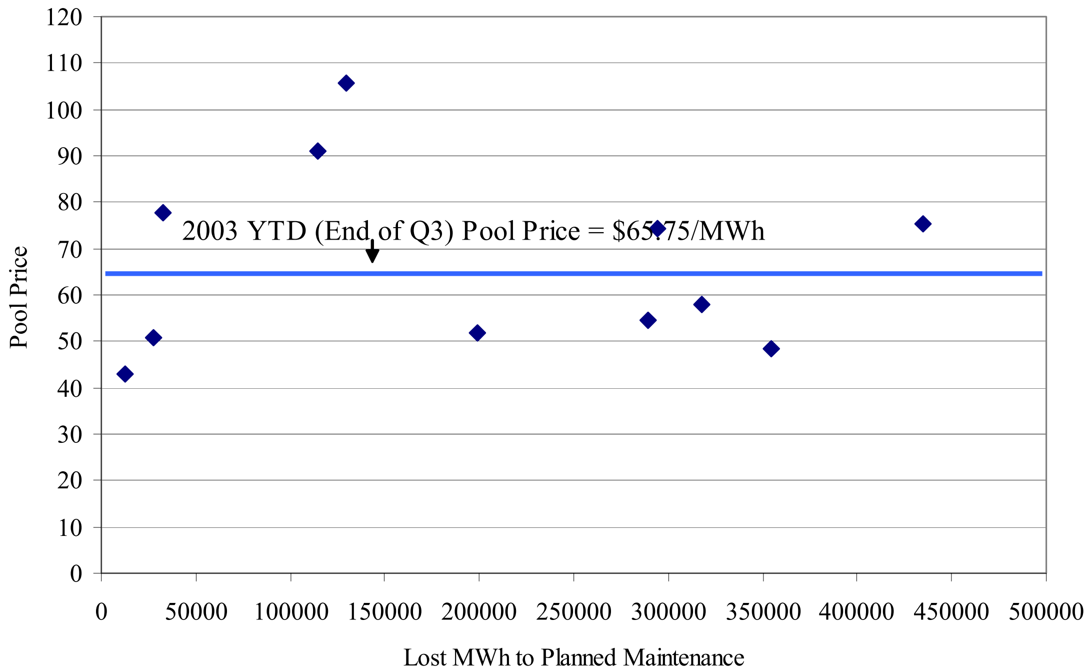
The MSA expects that the Owners will continue to refine their outage scheduling around the 30RAPP as they gain more experience with the PPAs in Alberta's competitive market environment. Because of the long term nature of the PPAs, the timing of outages around the 30RAPP will remain an important issue between the Owners and Buyers.

Figure 29 - Pool Price – 30 Day RAPP Vs Planned Outages (Major Turnarounds), PPA Coal Units



In terms of the Pool price, 60% of major planned outages have occurred when prevailing prices over the course of the outage have been below the 2003 year-to-date average Pool price of $65.75. **Figure 30** shows the distribution of major planned outages against the average Pool price that prevailed over the course of each outage event. The figure suggests that on average, planned outages are occurring during relatively low priced periods.

Figure 30 – Major Turnarounds vs. Pool Price



Conclusions

The *Outage and Derate Study* uses statistical techniques to understand broad relationships with respect to the availability of the PPA coal units. The analysis is not without its share of data problems. Planned outage data is ‘lumpy’, and therefore non-normally distributed. Also, the data tends to be ‘noisy’. For example, many factors influence the timing of a planned or maintenance outages, including (but not limited to) the nature of the maintenance work, availability of maintenance crews and replacement parts, corporate philosophies, portfolio position, and market conditions. Each factor adds noise to the data. Despite these issues, the analysis has produced results which, on a go-forward-basis, will be added to the MSA’s overall market monitoring program.

Recommendations

Recommendations arising from the *Outage and Derate Study* include:

- The MSA will continue the current monitoring which includes both *ad hoc* real-time monitoring and evaluation and the data filters designed to evaluate planned and unplanned outages at the PPA units in the context of their historical performance.

- The MSA will adopt the daily average outage versus forecast system demand regression and graph as a monitoring metric. This graph will be updated on both a quarterly and annual basis and considered for publication in an aggregate form in the Quarterly Report.
- Further work will be undertaken with respect to the outage versus the supply cushion metric. At present, there is no benchmark to aid in interpreting the absolute level of this metric. However, the metric appears useful in comparing outage behavior with respect to the supply cushion between and amongst portfolios.
- Because of its importance to market participants, the MSA will continue to monitor the relationship between planned outage behavior and the 30-day Rolling Average Pool Price (30RAPP).

3.3 FERC Trade Data

The Federal Energy and Regulatory Commission's (FERC) new electronic Quarterly Report includes all physical electricity trades conducted in the U.S. The MSA is scrutinizing this source of data as a way to make better interpretations of activities on the tie lines to Alberta. This new database is still a work in progress at FERC and further development is ongoing. The MSA is hopeful that this new source of important market data will be useful in its monitoring activities.

3.4 Physical Plant Audits

The MSA does not intend to implement a program of regular plant audits similar to what has been undertaken by the New York ISO. However, the MSA cannot preclude the possibility that a physical audit of a plant or transmission facility may, at some time, become necessary. The MSA held several discussions with staff at the NYISO regarding their procedures and have contacted firms that specialize in this type of work. The MSA is satisfied that it could assemble a well qualified team at short notice to undertake such an audit if it is deemed necessary.

4 OTHER MSA ACTIVITIES

4.1 EISG

The EISG is the Energy Inter-market Surveillance Group which is an association of electricity market surveillance peers located in North America, Australia, and New Zealand. The MSA presented at the fall meeting which was hosted by PJM.

4.2 Stakeholder Meetings

The MSA held its fall stakeholder meetings in Calgary on September 24 and in Edmonton on September 30. The meetings were well attended. The presentation from the meetings can be found at http://albertamsa.ca/files/Fall_Stakeholder_Meeting_2003(2).pdf .

4.3 MSA Staff

Brionie Brown, our summer student, returned to graduate engineering and business studies after making a positive contribution to several projects conducted by the MSA over the summer months. We wish Brionie continued success in her studies. In September, Natasha Solotina joined the MSA in the position of intern for a 12 month term. The MSA would like to welcome Natasha on board.