www.albertaMSA.ca

MSA REPORT

2003 Year in Review

31 March, 2004

MARKET SURVEILLANCE ADMINISTRATOR

TABLE OF CONTENTS

PAGE

LIST OF FIGURES

LIST OF TABLES

Executive Summary

In addition to this Year in Review report, beginning with the year ended December 31, 2003, the MSA also publishes an Annual Report under separate cover. The Year in Review report is intended to be a more technical version of the Annual Report and is similar in its presentation to the MSA Quarterly Reports.

The past year was eventful in the evolution of Alberta's electric industry with the proclamation of the new *Electric Utilities Act* in early June and the implementation of structural changes that accompanied the new Act. The new Act recognized the Independent System Operator, the Balancing Pool, and the MSA as new corporate entities, each under a distinct governance structure. For the MSA, these changes mean enhanced responsibilities, jurisdiction, independence, and tools to ensure Alberta's electricity markets operate in a fair, efficient, and openly competitive way.

The electricity markets continued to progress in 2003. The distribution of dispatch control in the wholesale market moved wider with the Balancing Pool's successful completion of the third phase of its MAP II process. As an additional benefit of this process, new players entered the Alberta market. As well, with the sale of its H.R. Milner generating station, the Balancing Pool moved out of the role of generator as it currently exercises no discretional control over dispatch rights to generating assets, although it continues to manage the aggregator function for the strip contracts.

The price of electricity fluctuated through the year with no clear trend exhibited. The average wholesale price for 2003 was $62.99/MWh which was up from $43.93/MWh in 2002 although the implied market heat rate declined to 10.1 GJ/MWh from 11.6 GJ/MWh in 2002. This indicates that higher gas prices in 2003 have tended to mask concurrent efficiency gains that have been made in a competitive generation market.

Peak demand increased just over 2% in 2003 relative to peak demand in the prior year while new supply in terms of generation additions more than compensated for this increase as almost 700 MW of capacity came on-line, representing an increase of approximately 6.2% in Alberta's installed generation base.

The retail market progressed in some respects through 2003 but still remained essentially in a holding pattern in terms of the residential switching off RRO. In all RRO eligible load categories at year-end, 7.4% of customers have chosen to sign a competitive contract with a retailer, representing a 0.3% increase from the end of Q3/03 and a 1.9% increase from the end of 2002.

With respect to the MSA's investigative mandate, the new Act brought a change by establishing a three member tribunal for the purpose of hearing matters brought by the MSA. The tribunal is given broad powers to address inappropriate conduct by market participants, or to recommend changes to market rules. In the period from declaration of the new Act to the end of 2003, the MSA did not take any matters to the hearing stage. Apart from bringing a matter to the tribunal, the MSA may conduct a formal investigation of the matter. The MSA is pleased to report that it was able to productively resolve issues that arose in the market in 2003 on an informal basis without taking the issues to the formal investigation stage.

Communicating to the market continued to be an important aspect of the MSA's role in 2003. In this regard, the MSA undertook a number of studies and communicated the findings of several of these in the MSA quarterly reports through the year. Among these studies was a review of zero dollar offers, a review of the AESO's Pool price forecast, and a detailed outages and derates analysis. It is the goal of the MSA that reviews of this nature improve the general understanding of issues and as a result, improve market efficiency.

The MSA looks forward to working with stakeholders in 2004 in taking a fair, efficient, and openly competitive market to the next level.

1 REVIEW OF THE WHOLESALE ELECTRICITY MARKET

1.1 Electricity Prices

The wholesale electricity market is a dynamic market in which prices can and do fluctuate hour to hour based on factors such as the availability of supply, which can be affected by outages and derates in the system at any point in time. Prices are also influenced by the collective offer behaviour of market participants which is reflected in a merit order or offer curve expressing volumes available for dispatch by the system controller at a given price. Pool price is set by the highest priced energy offer that is required to meet system demand. As in any competitive market, price acts as a signal to the market, from both a short-term perspective in responding to periodic increases in system demand or shortfalls in supply, and from a longer-term perspective in attracting capital investment in generation capacity. Although the MSA closely monitors market prices along with other significant market fundamentals, the MSA's interest in price is only to the extent that observed prices are the outcome of a fair, efficient, and openly competitive market.

As shown in **Table 1**, the average hourly Pool price in 2003 was $62.99/MWh which was up from $43.93/MWh in 2002. Monthly average prices ranged from $43.63 in September to $89.80 in March. The relatively higher Pool prices observed in the first quarter of 2003 were due in large measure to robust natural gas prices as Alberta spot gas prices were averaging between $6.00/GJ and $8.00/GJ and on occasion, spiked into the $15.00/GJ range. With moderating gas prices seen through the balance of 2003, the relatively higher average prices observed in July and October were more directly a function of lower coal unit availability in those months. Likewise, relatively low average prices in September were related to above average base load coal availability.

Market prices were generally above 2002 levels as shown by the duration curve in **Figure 1** which indicates that prices were higher approximately 92% of the time in 2003 as compared to 2002.

While market prices were higher on average as compared to 2002, **Figure 2** shows that price volatility moved lower indicating that prices were more narrowly distributed relative to average prices.

Table 1 – Pool Price Statistics 2003

	Average Price	On-Pk Price	Off-Pk Price	Std Dev[1]	Coeff. Variation[2]
Jan	80.52	93.78	63.70	94.47	117%
Feb	81.23	99.42	56.98	82.15	101%
Mar	89.80	93.24	85.43	84.77	94%
Apr	51.68	62.57	36.71	50.74	98%
May	56.50	69.57	39.94	62.87	111%
Jun	44.47	59.57	25.59	59.25	133%
Jul	87.91	106.25	64.64	98.72	112%
Aug	55.67	66.34	42.12	38.90	70%
Sep	43.63	53.26	31.58	43.93	101%
Oct	67.45	87.62	39.63	78.96	117%
Nov	52.56	61.10	42.80	48.37	92%
Dec	44.34	52.52	33.95	37.62	85%
2003	62.99	75.54	46.98	70.40	112%
2002	43.93	56.04	28.47	64.77	147%

1 - Standard Deviation of hourly pool prices for the period

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

Figure 1 – Pool Price Duration Curves

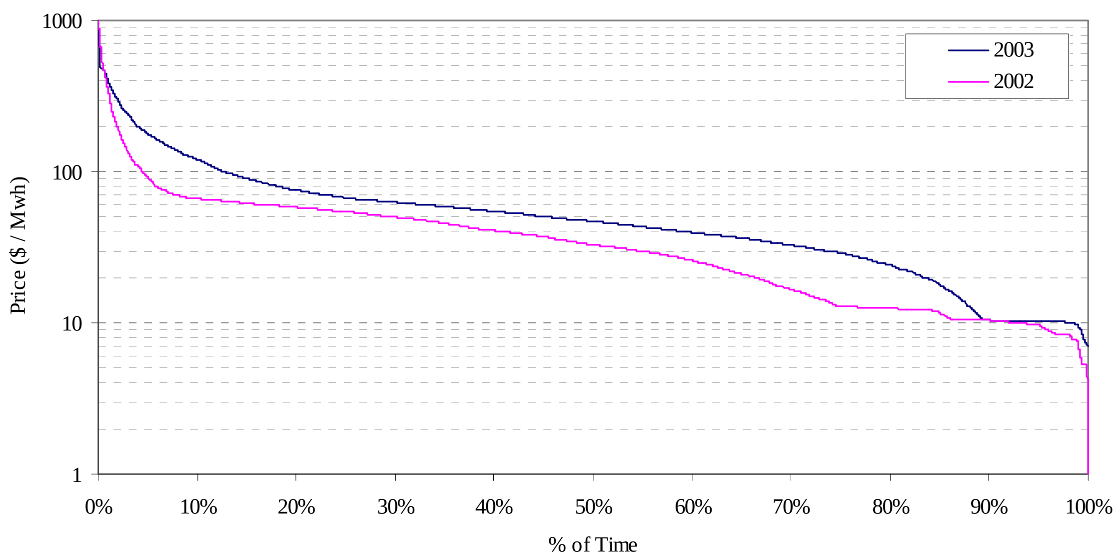
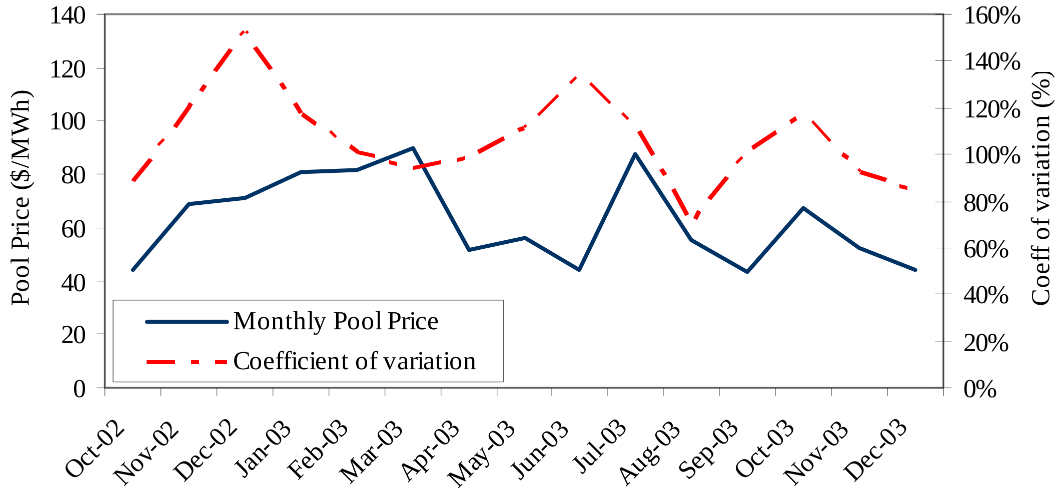


Figure 2 - Pool Price with Pool Price Volatility

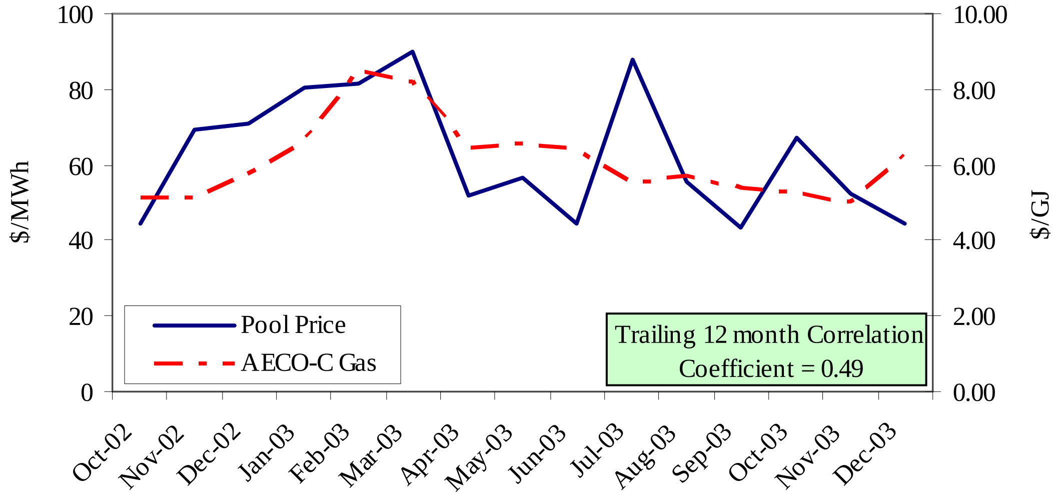


1.2 Natural Gas Prices

Natural gas prices are an important market fundamental relative to the Alberta electricity market since gas fuelled generation comprises over 40% of installed capacity in the Alberta system and collectively sets system margin price on average, about half the time on an all-hours basis. Almost all new capacity brought on line in recent years has been gas fuelled and gas prices serve as an important signal to potential entrants to the electricity market.

Alberta gas prices were significantly stronger year over year as the 2003 average price rose to $6.31/GJ vs $3.83/GJ in 2002. **Figure 3** shows monthly average gas prices over the last 15 month period together with monthly average Pool prices over the same period. The trailing 12 month correlation between the two declined from 0.83 at the end of Q2/03 to 0.49 at the end of Q4/03. The change in correlation suggests that the variation in Pool price in the second half of 2003 was driven by market variables other than Alberta gas prices. This is not such a surprising result as it may first appear. There is no doubt that the cost of gas is factored into the offer strategies of generators since ultimately they must recover this cost. Other market fundamentals however, may exert a stronger or lesser influence on Pool price in certain periods in a competitive market given that offer strategies are dynamic and are not simply based on variable cost. For example, higher frequency of short-term market tightness may result in higher prices than gas prices would suggest. This was the case in the second half of 2003 where the frequency of short term market tightness was significantly higher than the first half of the year. This is also indicated by average market tightness as approximated by coal unit availability.

Figure 3 - Pool Price with AECO - C Gas Price



1.3 Price Setters

Figure 4 shows a profile of the 5 most frequent marginal price setting participants in both 2003 and 2002 together with the weighted average price at which they set SMP. Note that the participant at each ranking is not necessarily the same for 2003 and 2002. The most frequent price setter in 2003 set price 18% of the time and did so at a weighted average SMP of $49.22/MWh. In 2002, the leading price setter set price 25% of the time at a weighted average SMP of $27.72. This demonstrates that price setting continues to be highly contested with no one participant having a disproportionate position.

Figure 4 - Price Setters by Participant (All Hours)

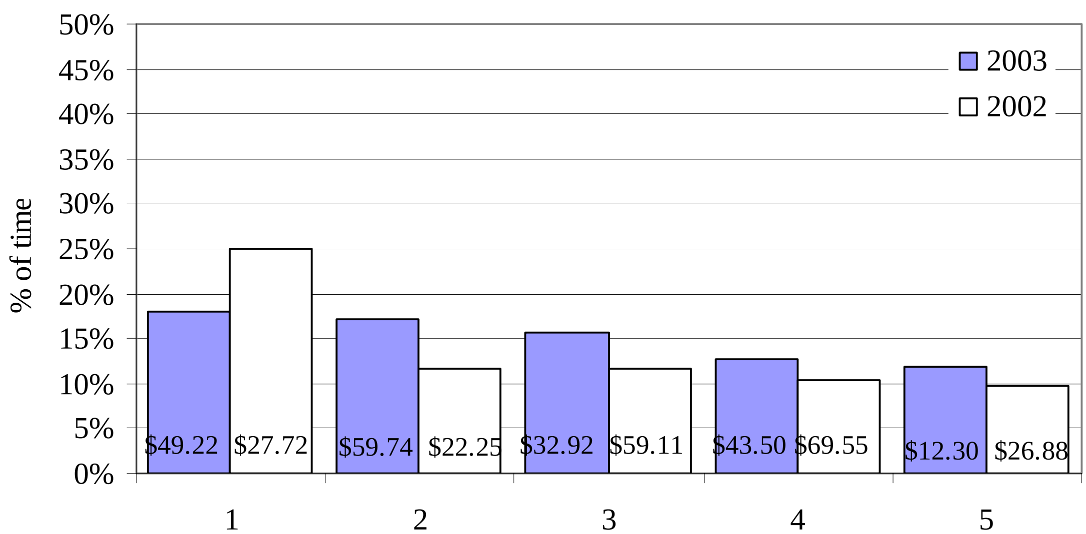
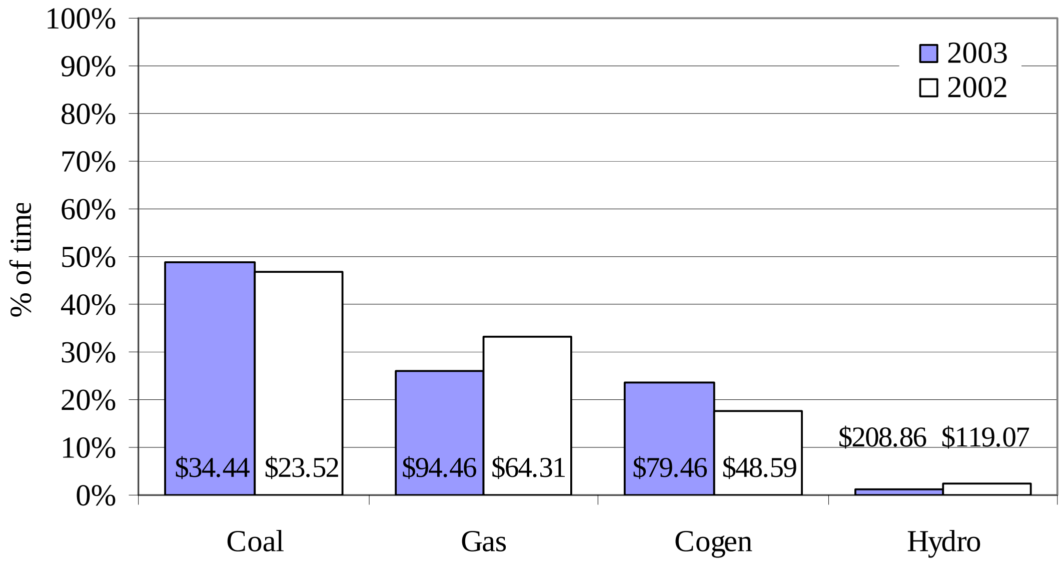


Figure 5 shows price setters classified by fuel type in 2003 compared to 2002. Coal set price at a similar level in 2003 as in 2002 although at a somewhat higher average price. Gas units collectively (ie: including cogen) set price at a similar frequency in 2003 as well although separately, cogen units were more frequent price setters as compared to 2002.

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



1.4 Implied Market Heat Rate

The implied market heat rate (IMHR) is a metric that describes the profitability of the market from the perspective of gas generators. **Figure 6** shows the daily implied market heat rate for 2003 on a flat (all hours) basis. As shown in **Table 2**, the implied market heat rates fluctuated through 2003, peaking in July due to strong Pool prices together with a moderating gas market. The IMHR declined on both an on-peak and an off-peak basis in Q4/03 relative to the previous quarter contributing to an all hours average for 2003 of 10.1 GJ/MWh. **Figure 6** shows duration curves for heat rates observed through 2003 relative to the two prior years, and shows the approximate heat rates of a new combined cycle plant and of Clover Bar for comparison. In 2003, a new combined cycle plant would have recovered its fuel costs 66% of the time while in 2002, the same plant would have recovered its fuel costs 77% of the time. While Pool prices were higher this year over last, the IMHR shows that it was in fact a less profitable year for gas generators. It should be noted that this metric does not take into account other aspects of variable operating costs or a return on invested capital.

Figure 6 – Heat Rate Duration Curves (All Hours)

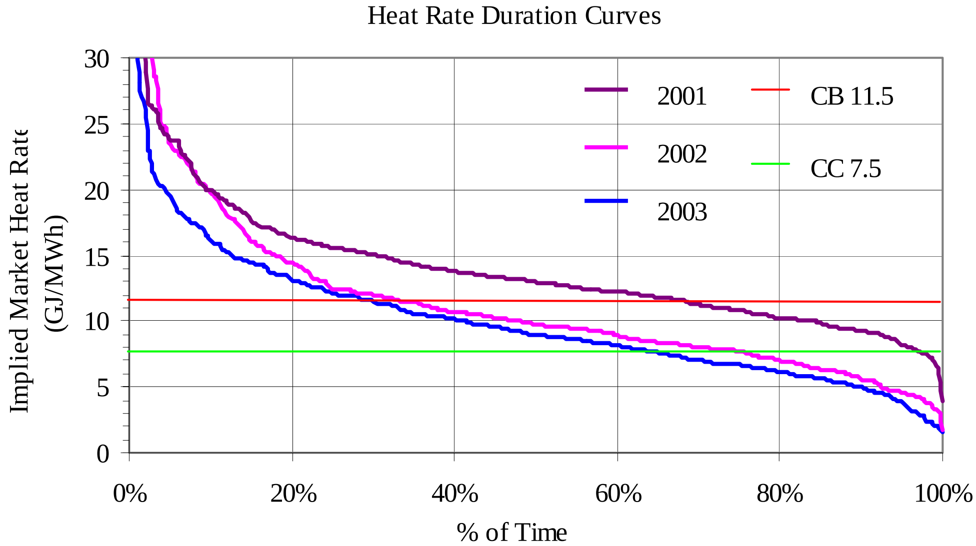


Table 2 - Implied Market Heat Rates by Month (2003)

Month	On-Peak	Off-Peak	All Hours
January	14.0	9.4	12.0
February	11.5	6.5	9.4
March	11.8	10.0	11.2
April	9.7	5.6	8.0
May	11.3	5.5	9.1
June	8.7	3.8	6.8
July	19.2	11.3	15.9
August	11.6	7.1	9.7
September	9.8	5.0	8.1
October	14.6	7.1	12.9
November	9.7	8.5	10.6
December	7.4	5.0	7.2
Average	11.6	7.1	10.1

1.5 New AESO Rules

With the inception of the AESO, Power Pool Rules, Power Pool Code, Transmission Administrator Operating Policies, and Settlement System Code were amalgamated into a new set of AESO Rules. To review the resulting rule changes and structure of the new rules see the MSA Q3/03 Report at http://www.albertamsa.ca/files/MSA-Q3.pdf. There were no significant changes to AESO Rules in Q4/03.

1.6 New Supply and Load Growth

Generation additions in 2003 increased relative to additions to the system in the prior year. Over 600 MW of new generation came on-line this year, representing an increase in installed capacity of about 6.2%. This includes the following notable additions:

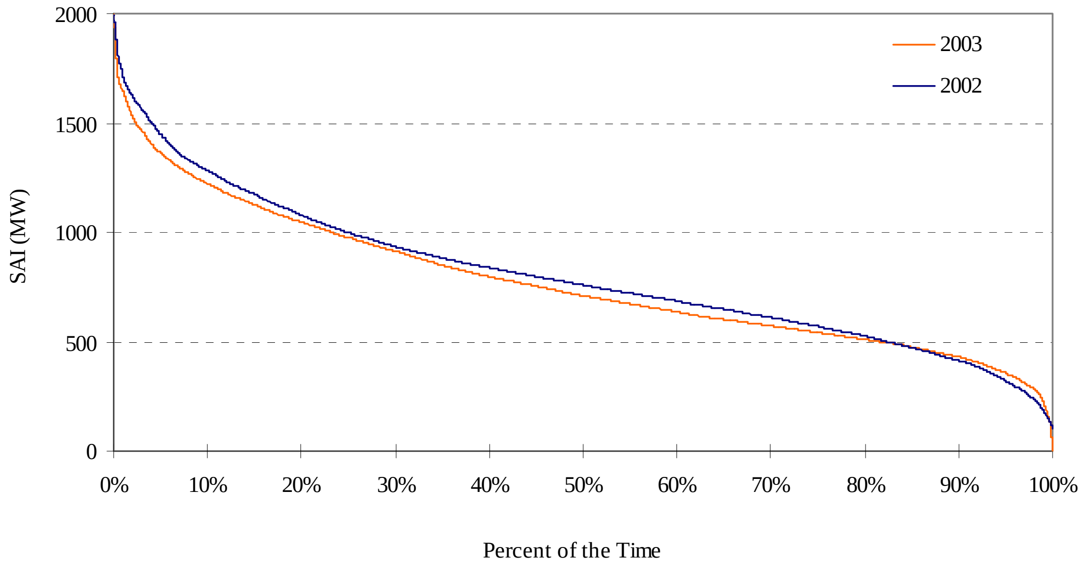
- Calgary – Calpine – Gas (283 MW)
- Foster Creek – Encana – Gas (83 MW)
- Old Man – Atco Power – Hydro (32 MW)
- McBride Lake – Vision Quest – Wind (40 MW)
- Scotford – Shell / Atco Power – Cogen (184 MW)
- City of Medicine Hat – Gas (42 MW)

Average system demand in 2003 ranged from 6745 MW in the month of June to 7633 MW in December. Peak demand in 2003 reached 8758 MW which occurred on December 11 in HE 18 at a price of $78.21/Mwh. Peak demand in 2003 represented an increase of just over 2% relative to peak demand in 2002. Overall, supply additions in 2003 more than matched the year over year increase in peak system demand.

1.7 Supply Availability Index (SAI)

As in most competitive markets, the market price for electricity is influenced by the tightness of the market or the relative difference between demand and short term available supply. This relationship is not linear in nature whereby a change in supply is reflected by a similar change in price at every level of supply, rather the strength of the relationship varies depending on the shape of the supply offer curve. The SAI is defined as the remaining capacity in the merit order above dispatch which represents the supply available to the system controller within the hour. Imports are not considered in this metric since the interchange schedule is fixed prior to the next hour. **Figure 7** shows duration curves for SAI in 2003 relative to 2002. While SAI was marginally lower approximately 80% of the time in 2003 as compared to 2002, it is at the low SAI end of the curve where price response is most pronounced and 2003 showed higher SAI in this regard. Availability and price are generally negatively correlated meaning that price tends to increase as availability decreases. In 2003 the correlation coefficient between SAI and hourly pool price was determined as -0.44. This compares to -0.47 in 2002, indicating that the correlation is quite consistent over the long term.

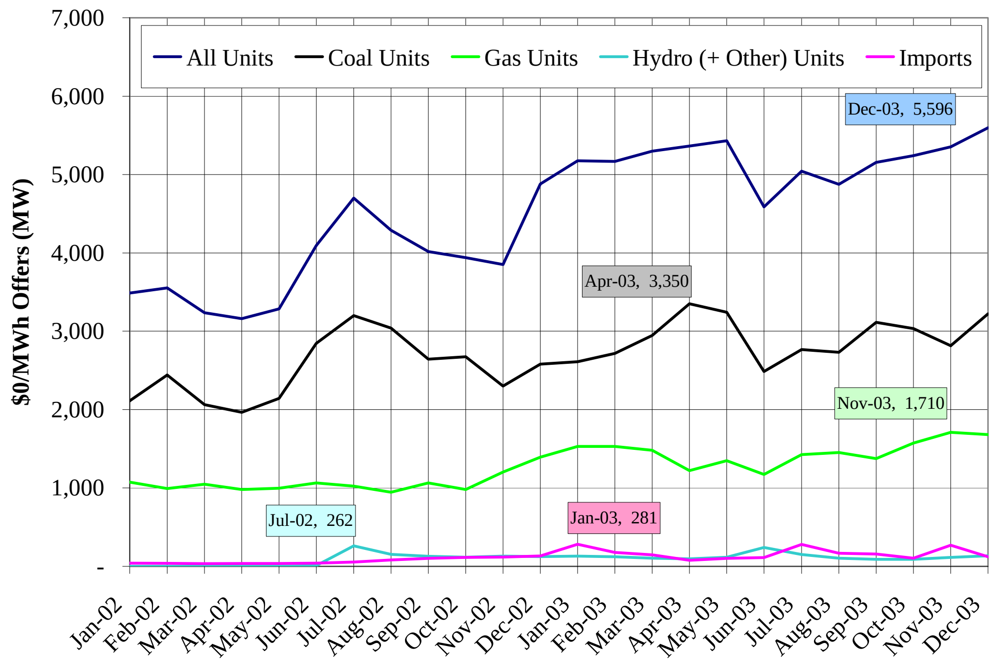
Figure 7 – SAI Duration Curves



1.8 Zero Offers

During 2003 the MSA reported quarterly statistics regarding zero dollar offers into the merit order. Zero dollar offer behavior has persisted throughout the year and has in fact increased during Q4. **Figure 8** plots monthly average MW offered at $0/MWh by unit type for 2002 and 2003. Monthly high values for each generation type over the two year period are also shown in the figure.

Figure 8 - Zero Dollar Offers



The figure shows that after decreasing in Q3/03, overall zero offers have taken an up-swing in Q4/03. Hourly zero dollar offers averaged 5,397 MW in Q4/03, increasing more than 370 MW from the Q3/03 average of 5,025 MW. Even more significantly, this is an increase of over 1,150 MW from the same period last year in which zero dollar offers averaged only 4,224 MW.

Overall zero dollar offers reached an all-time high of 5,596 MW in December 2003. Although none of the fuel-specific zero offer volumes peaked in December, zero dollar offers were higher than typical for both coal and gas-fired generation. The increased volume of zero dollar offers could be attributed to relatively high availability of most units, likely in response to anticipated increased winter demand. A similar increase in zero offer volumes was observed from November to December 2002, indicating that the jump is potentially seasonal.

On an annual basis, 2002 zero offers averaged 3,875 MW and jumped up to 5,190 MW in 2003. This is an increase of over 1,300 MW. Although coal units still make up the majority of zero dollar offer volumes, the most notable change in zero dollar offer behavior since last year can be attributed to gas-fired generation. Average annual zero offers of gas-fired units have increased by over 37% from 2002 to 2003 while the increase for coal-fired units is only approximately 17%. The addition of a number of new gas-fired units in the province (particularly combined-cycle and co-generation units which tend to offer a significant portion of their capacity at $0/MWh) is likely the primary driver behind this change. Over the same period, the total capacity of coal-fired generation in the province has actually decreased through unit retirement.

Despite the increase in overall zero offers over the year, the MSA does not believe that this behavior is negatively impacting 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 2003 and highlights the tie-line activity in Q4/03.

Table 3 – 2003 Tie Line Activity

	BC			Saskatchewan			Overall		
	Imports	Exports	Net Imports	Imports	Exports	Net Imports	Imports	Exports	Net Imports
	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh
January	127,700	71,600	56,100	81,000	1,700	79,300	208,700	73,300	135,400
February	34,900	78,400	(43,500)	82,900	1,800	81,100	117,800	80,200	37,600
March	65,000	76,800	(11,800)	42,300	6,000	36,300	107,300	82,800	24,500
Q1	227,600	226,800	800	206,200	9,500	196,700	433,800	236,300	197,500
April	46,800	112,700	(65,900)	19,700	4,600	15,100	66,500	117,300	(50,800)
May	49,200	135,500	(86,300)	30,000	1,300	28,700	79,200	136,800	(57,600)
June	50,100	90,100	(40,000)	32,900	1,600	31,300	83,000	91,700	(8,700)
Q2	146,100	338,300	(192,200)	82,600	7,500	75,100	228,700	345,800	(117,100)
July	105,400	80,100	25,300	37,500	200	37,300	142,900	80,300	62,600
August	52,700	100,700	(48,000)	41,700	4,000	37,700	94,400	104,700	(10,300)
September	54,100	140,100	(86,000)	12,700	2,600	10,100	66,800	142,700	(75,900)
Q3	212,200	320,900	(108,700)	91,900	6,800	85,100	304,100	327,700	(23,600)
October	61,800	78,100	(16,300)	12,700	3,000	9,700	74,500	81,100	(6,600)
November	176,600	81,500	95,100	14,300	4,300	10,000	190,900	85,800	105,100
December	71,800	135,100	(63,300)	15,500	2,300	13,200	87,300	137,400	(50,100)
Q4	310,200	294,700	15,500	42,500	9,600	32,900	352,700	304,300	48,400
Total	**896,100**	**1,180,700**	**(284,600)**	**423,200**	**33,400**	**389,800**	**1,319,300**	**1,214,100**	**105,200**

Note: Negative net imports indicate net exports

In Q4/03, Alberta was an overall net importer. Although on a monthly basis Alberta was an overall net exporter for two of the three months in the quarter, heavy importing on the BC tie-line in November dominated quarterly tie-line activity resulting in net imports of almost 50,000 MWh for the quarter. The 176,600 MWh imported over the BC tie-line in November is the highest monthly value of imports on record (since January 2000). This high level of imports is possibly due to a combination of relatively low unit availability during the month and higher prices in Alberta relative to other markets in the Western US. It was not supported by particularly high prices in Alberta as the average Pool price in November was only $52.56/MWh – quite a bit less than the average annual Pool price.

Over the entire year, Alberta imported over 1.3 million MWh of electricity and exported over 1.2 million MWh of electricity to be an overall net importer. On the BC tie-line, export volumes were 1.3 times that of import volumes while import activity was more than ten times greater on the Saskatchewan tie-line than export activity on the same line.

Figure 9 - Market Share of Importers and Exporters, Q4/03

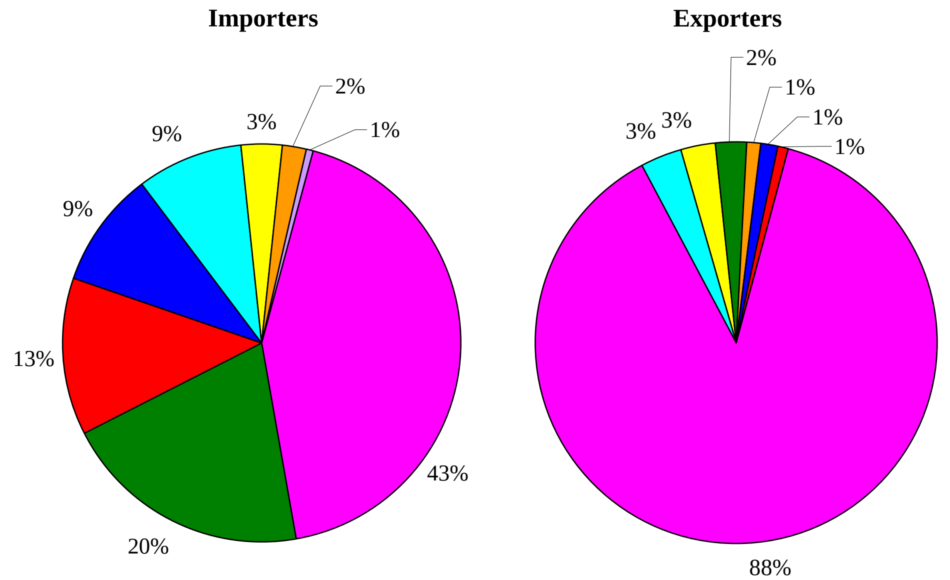


Figure 10 - Market Share of Importers and Exporters, 2003

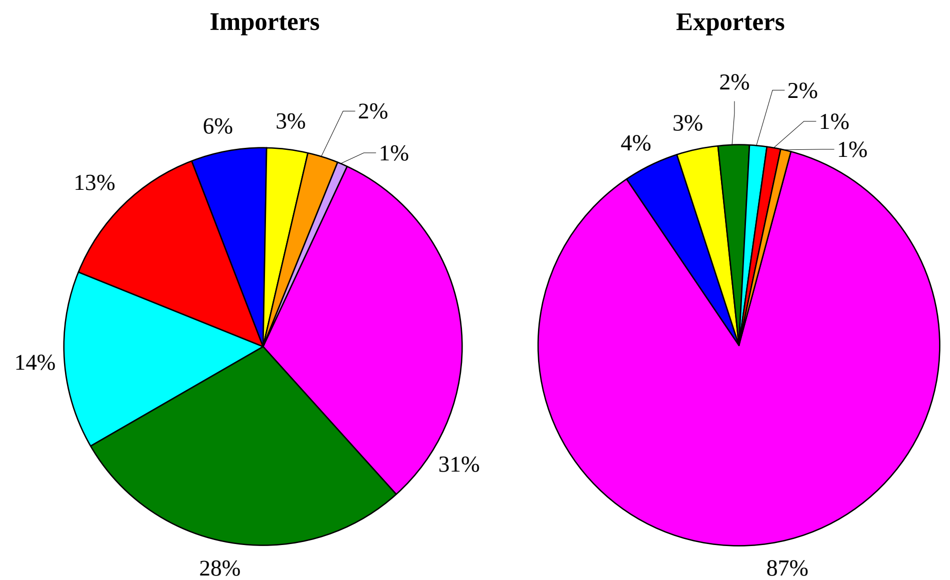


Figure 9 shows the distribution of market shares of importers and exporters on the BC and Saskatchewan tie-lines (combined) in Q4/03. **Figure 10** shows the same information for the whole of 2003. Market share of importers was reasonably well distributed in Q4/03, although not as well distributed as it was in Q3/03 or for the entire year. The dominant importer (Powerex) had a 43% market share in Q4/03 compared to a 31% market share last quarter and for the year. While the market share

distribution is slightly different between Q4 and 2003 overall, the relative order of participants by market share varies between the two data sets. This shows that with the exception of the two most active importers, relative market share of importers changes with time depending on each participant's market position. For example, if a generator was in a short position due to a unit outage within the province it might typically import more energy during that period.

Market share of exporters is more clearly dominated by a single participant on both a quarterly and an annual basis. This is not surprising as this participant (Powerex) holds all firm transmission rights on the BC tie-line and generally makes use of its export transmission capacity in most off-peak hours. As in the case of importers, individual exporters market shares also appear to vary with time as a function of individual market positions.

Figure 11 shows a duration curve of tie-line utilization for Q4/03 and **Figure 12** shows a duration curve of tie-line utilization for the whole of 2003 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[1]. 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, prices in other markets and market position contribute to determining whether or not it is profitable to make use of the available tie-line capacity.

[1] For example, if the ATC of an intertie for an hour was 500 MW and 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 – Q4/2003

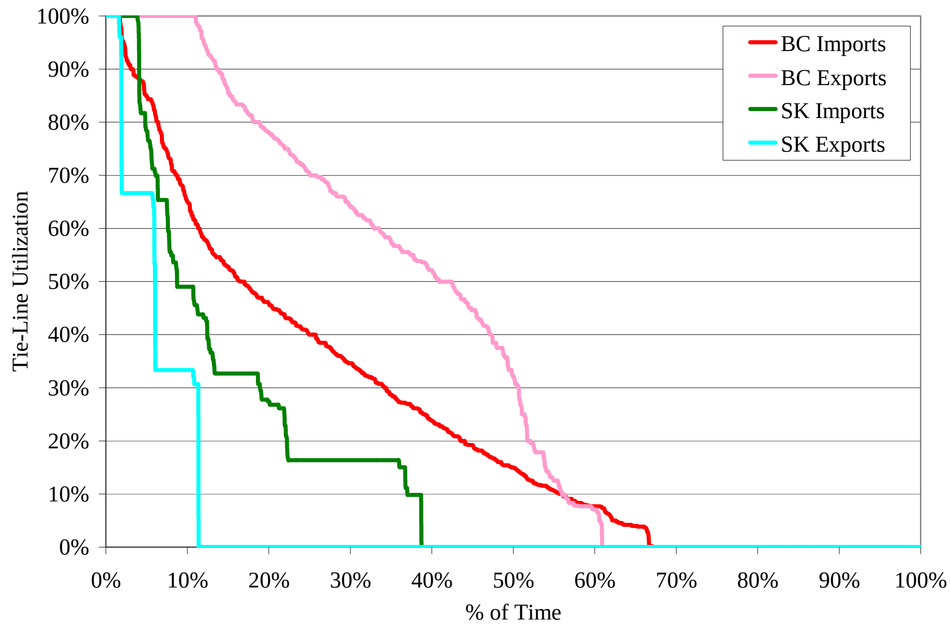
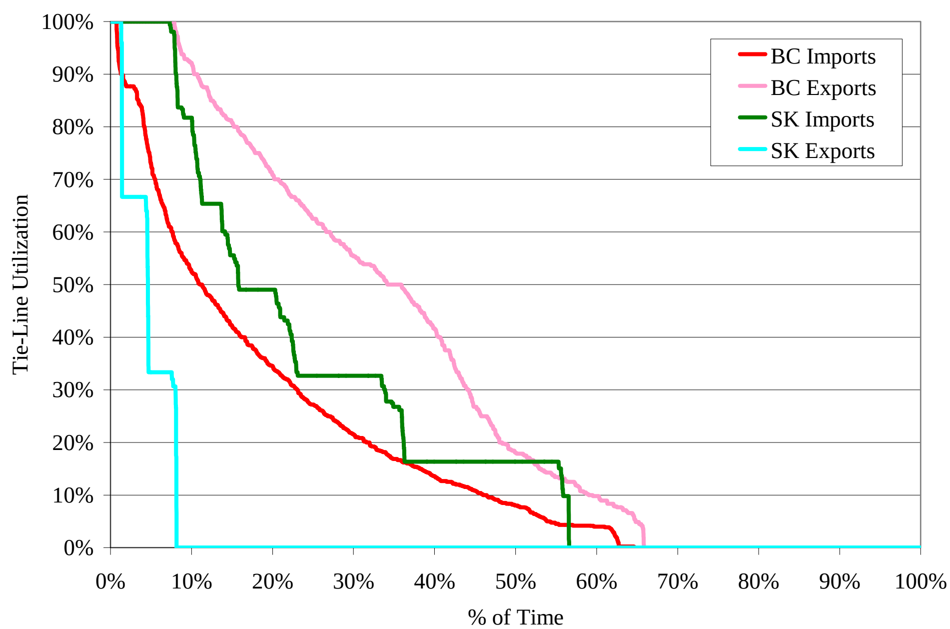


Figure 12 - Tie-Line Utilization –2003



The figures show that there is unutilized capacity available on both tie-lines most of the time. Utilization for Q4 and for the entire year vary marginally, but overall the BC export capacity is utilized most while the Saskatchewan export capacity is the least utilized. In a relative sense, the BC import, BC export and Saskatchewan export capacities were more fully used in Q4 than on average for the rest of the year. Only the Saskatchewan import capacity was used less in Q4 relative to 2003 as a whole.

A number of tie-line outages occurred during Q4/03. The most significant outage was a scheduled daily maintenance outage (the line was out of service only during working hours as opposed to the full 24 hours of the day) of the BC tie-line which occurred from October 6 through 10 and resumed from October 14 through 16. In addition, the BC tie-line endured some heavy derates during the quarter due to some generation and transmission constraints within the province. The most prevalent example of this is the occurrence of the Calgary Area capacitor bank being out of service. The capacitor bank outage causes the ATC of the BC export tie-line to be reduced as a function of the Alberta internal load. This was the case for many of the on-peak hours in Q4/03 and for the highest demand hours of the day, the BC export ATC was often reduced to zero[2].

Continuous outages (outages persisted for the full 24 hours of the day without interruption) of the Saskatchewan tie-line occurred from October 20 through 23 and October 28 through 30.

Activity on the tie-lines can be highly dependent on Pool price. **Figures 13 and 14** 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 October 2002 through December 2003 period. During Q4/03, 76% of imports occurred during on-peak hours and 93% of exports occurred during off-peak hours while during the entire 2003 period 76% of imports also occurred during on-peak hours and 80% of exports occurred during off-peak hours. Therefore comparisons with on and off-peak prices are appropriate.

[2] Note that utilization of the tie-line cannot be calculated for hours when the ATC is zero. Utilization is measured only when it is possible to move energy across the line.

Figure 13 - Imports and On-Peak Pool Price

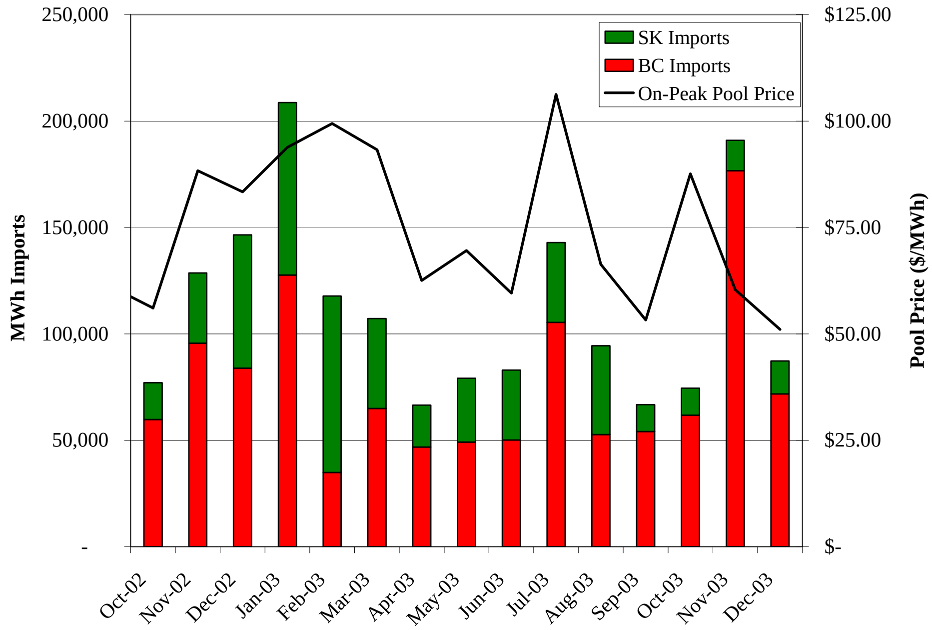
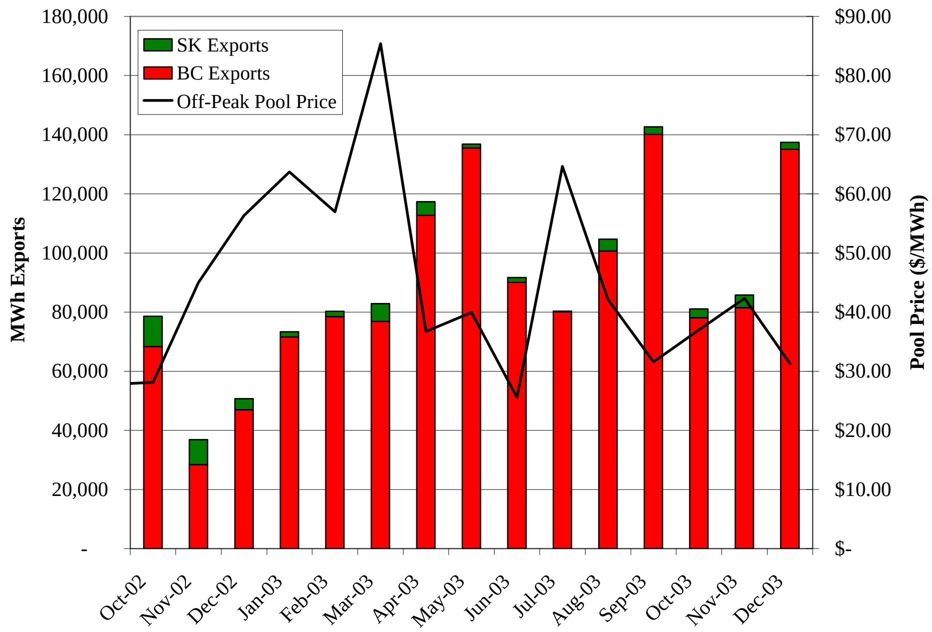


Figure 14 - Exports and Off-Peak Pool Price



During Q4/03 import volumes do not correspond particularly well with on-peak Pool prices as import volumes were lowest in the month with the highest on-peak price (October). The counter-intuitive relationship between on-peak price and import volumes extends to a quarterly view. 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 whereas in Q4/03 over 352,000 MWh were imported at an average price of only $66.34/MWh. This indicates that either factors other than Pool price were driving imports over the quarter or that the volume of imports has had a significant impact on price. Importers are required to offer into the market at a price of $0/MWh and therefore have a tendency to lower the prevailing Pool price.

During Q4/03 the inverse relationship between off-peak Pool price and export volumes is not as clear as it has been in past months. Exports were fairly moderate through October and November and almost doubled into December when the average off-peak price fell to just over $31.00/MWh. Total export volumes for Q4/03 (304,000 MWh) were in the same range as for Q3/03 (328,000 MWh) but were almost double what they were for the same period last year. This can be at least partially attributed to a lower average off-peak Pool price in Q4/03 than in Q4/02.

Figure 15 - Price Paid for Imports and Exports

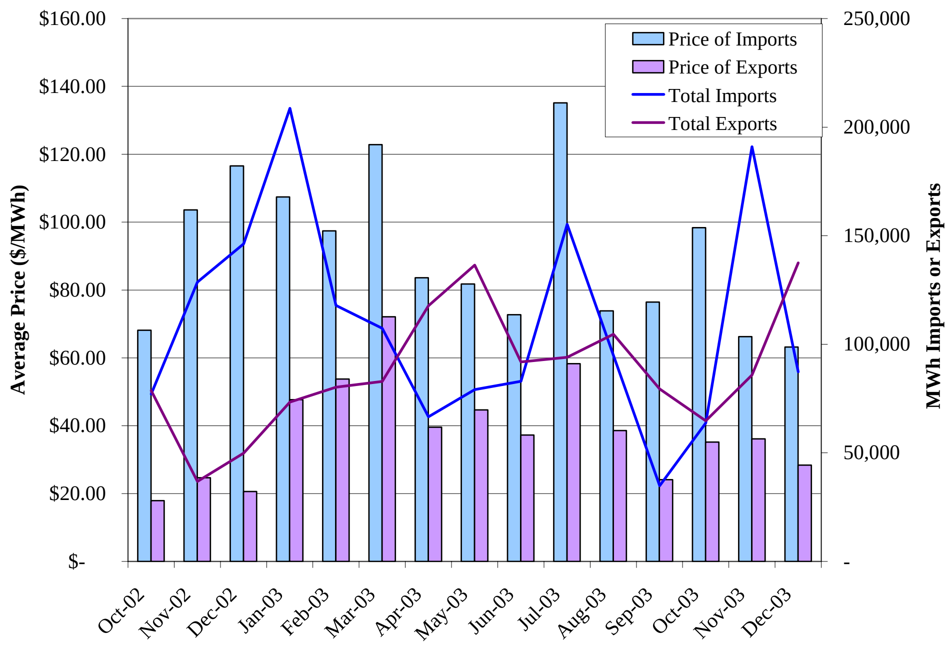


Figure 15 plots the volume-weighted monthly average price paid to importers and paid by exporters along with total monthly imports and exports for the past 15 months. In general, the average price received for imports is directly related to the volume of imports in the month while the average price paid for exports is 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 also have an impact on the economics of importing and exporting electricity into and out of the province. Although neither of Alberta's immediate neighbors operates a competitive electricity market, electricity is often moved through these areas and into adjoining markets. **Figures 16 and 17** 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 1.35 CDN/US.

Figure 16 - On-Peak Prices in Other Markets

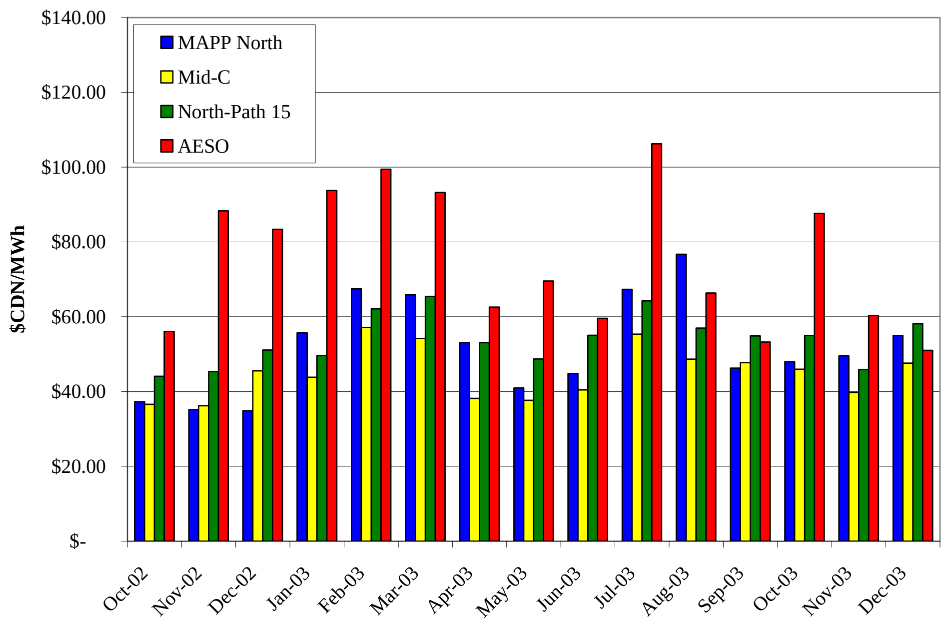
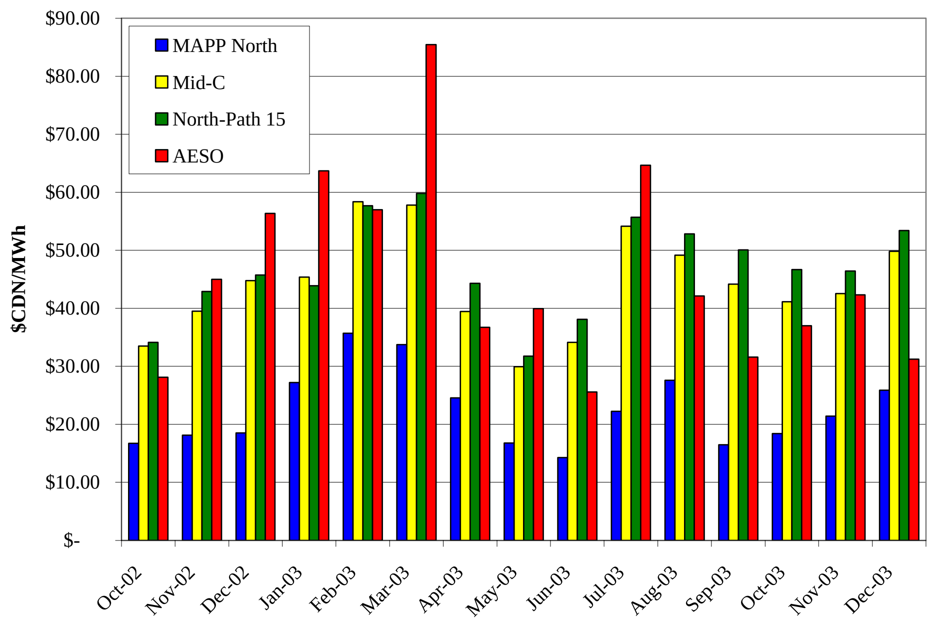


Figure 17 - Off-Peak Prices in Other Markets



On-peak prices in Alberta started strong in Q4/03 and decreased through November and December. On-peak prices in other markets were flatter than Alberta prices over the quarter. Throughout October and November prices were higher in Alberta relative to other markets, potentially encouraging importing. During December the price differential reversed. These price differentials are in line with observed import/export volumes and provide a possible explanation for the high volumes of imports over the BC tie-line in November. Over the course of the year, Alberta prices have been more volatile than prices in the three other markets.

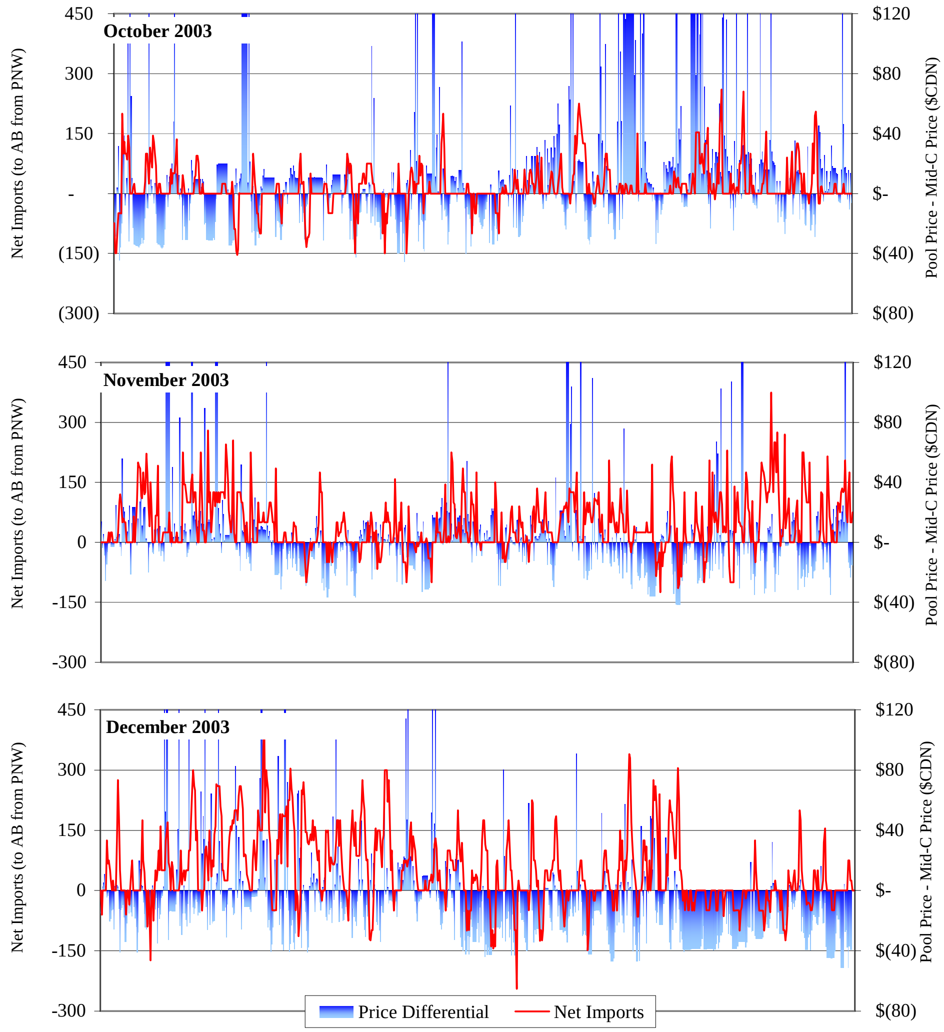
Alberta off-peak prices remained strong compared to MAPP-North prices throughout Q4/03. This relative pricing has been prevalent over the past five quarters. Off-peak prices at both Mid-C and North-Path 15 continued to be stronger than off-peak Alberta prices, particularly in December when prices in the Pacific Northwest averaged near $50.00/MWh compared to about $30.00/MWh in Alberta. 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. However, energy is often moved through BC and Saskatchewan to markets in the US[3]. **Figures 18 and 19** attempt to capture the economic use of the BC and Saskatchewan tie-lines over the last quarter. In the graphs, hourly net imports from jurisdictions beyond BC (to the West) and Saskatchewan (to the east) 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. Note that daily index prices from Mid-C and MAPP-N are used for this analysis and not actual trade prices. The analysis should therefore be considered 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.

When measured on this basis it was found that 79% of the energy moving through BC and 94% of the energy moving through Saskatchewan appeared to be moving in the economically efficient direction.

[3] The difference in the price at which energy can be bought and sold gives an indication of the economically correct direction for energy to be moving across the tie-line. For example, if the Price at Mid-C is greater than the Pool price in Alberta, it would be most economically efficient to buy energy in Alberta and sell it at Mid-C (i.e. exporting), as long as the price difference exceeds the cost of transmission. Energy being imported in such a price scenario would be seen to be economically inefficient use of the tie-line.

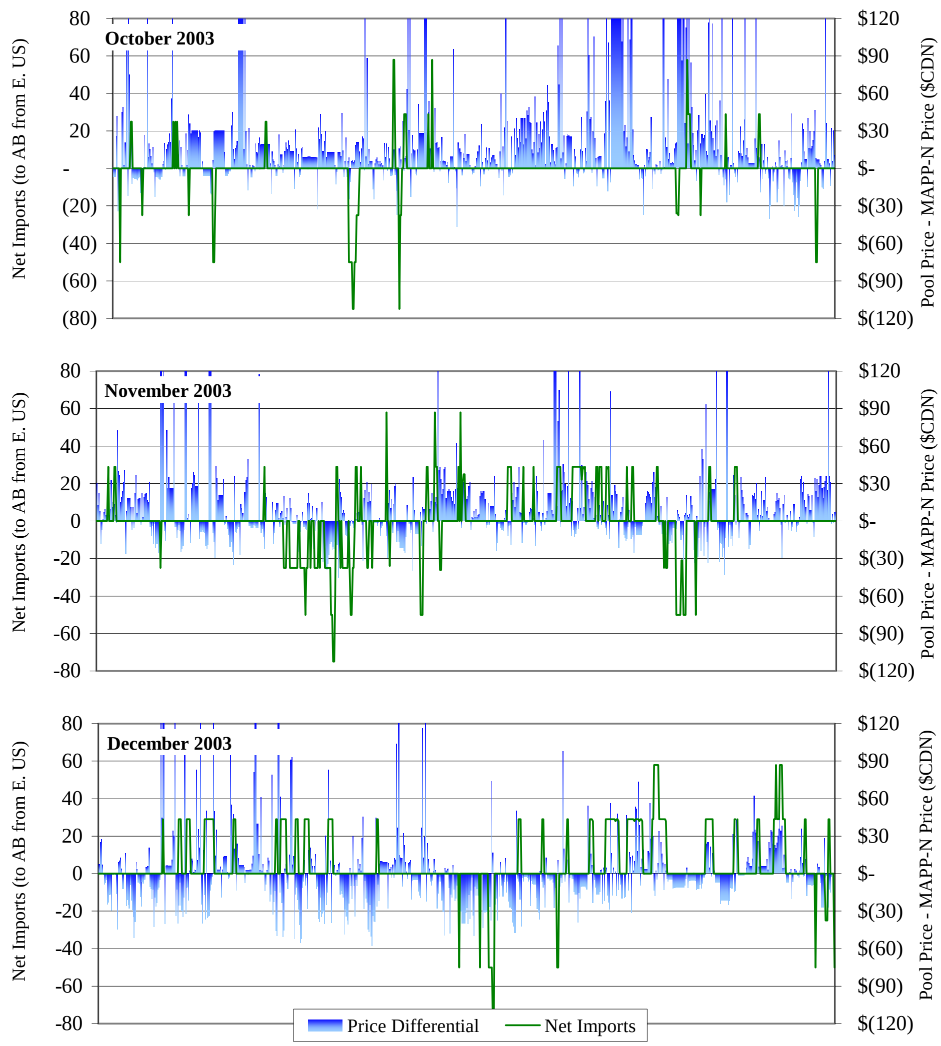
Figure 18 - Economic Use of the BC Tie Line



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

Figure 18 indicates that for the majority of Q4/03, energy moving through BC was traveling in the right economic direction. Towards the end of November relatively high volumes of imports from the Pacific Northwest were observed during times when the price differential indicated that it would be more economically efficient to export. Most of these imports occurred during the on-peak hours when it is usually more profitable to import than export. This apparent inefficient use of the tie-line could be the result of a "bad guess" on the part of the importer(s) or the result of 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 or other market conditions. There were no instances during the quarter when the MSA observed economically inefficient tie-line use which it felt was untoward.

Figure 19 - Economic Use of the Saskachewan Tie Line



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

Much smaller volumes of electricity flow through Saskatchewan than flow through BC – the majority of which flows to/from Manitoba – another regulated market. As such, the information shown in **Figure 19** is not as telling as that in **Figure 18** and should be interpreted as such. That being said, most of the imports and exports moving through Saskatchewan flowed in the right economic direction – particularly during times of high price differentials. Some instances of apparent uneconomic importing and exporting were observed, but none of this activity was seen as inappropriate.

Note that the MSA started monitoring economic use of the tie-lines mid-way through 2003 and is therefore unable to comment on changes in behavior relative to the same period last year or for the whole of 2003.

1.10 Outages and Derates

The MSA monitors the outages and derates of generating units in Alberta. Of particular interest are the previously regulated coal generating units that are now operated under the terms and conditions of the Power Purchase Arrangements (PPAs). Monitoring of outages and derates was prompted by the design of the PPAs wherein a PPA unit has two different parties who are owner/operator and buyer of dispatch rights for the same generating unit capacity. Therefore, outages at these plants impact both the plant owners' portfolios and the PPA buyers' portfolios. This monitoring was also prompted by the fact that 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.

Figure 20 illustrates planned and unplanned outage levels for 2001, 2002, and 2003. The figure illustrates that the overall PPA outage level at the coal-fired facilities has been relatively stable from 2001 through 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 6.5% in 2001, up to

8.1% in 2002 and up slightly to 8.5% for 2003[4]. *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 6.1% for 2003. *Owner-C* saw its overall PPA coal outage level range from 14.2% in 2001 to 13.1% in 2002 and 12.3% in 2003.

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. 2003 has seen a planned outage level of 5.5%, which represent about 53% of all outages.

It should be noted that although outages have traditionally been considered either planned, forced or maintenance, the interpretation of these definitions can be somewhat subjective. 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).

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

Figure 20 - Planned and Unplanned Outage - PPA Coal-Fired Units

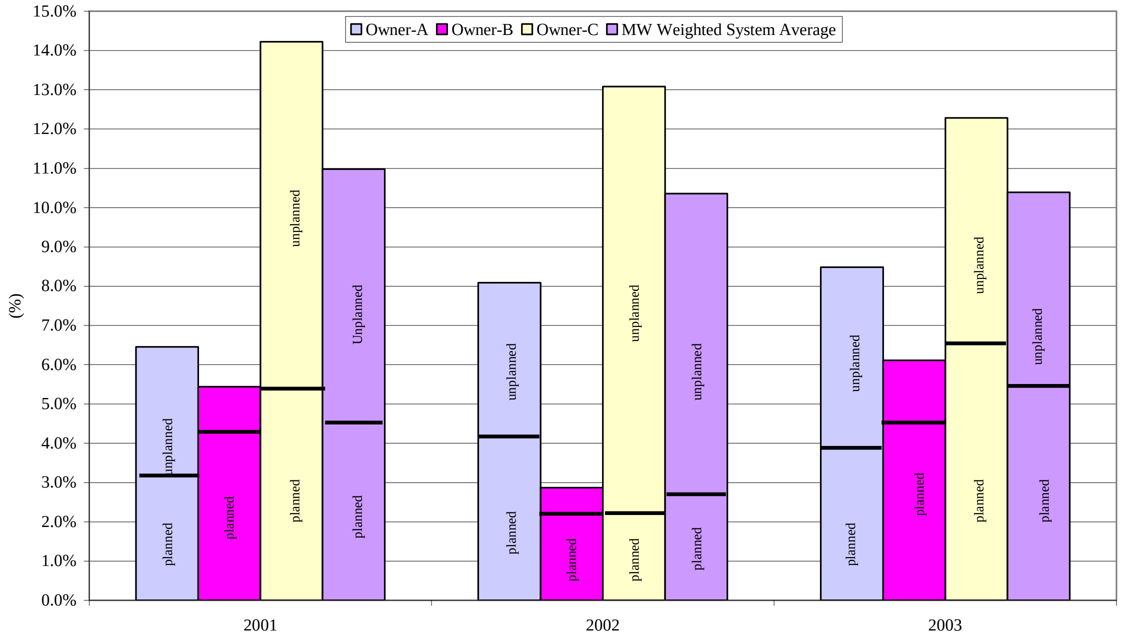


Table 4 reports unplanned outages on a quarterly basis for 2003, as well as Annual averages for 2001 - 2003. On a quarterly basis, overall MW weighted average unplanned outages (the number of MWh's lost to forced and maintenance outage by the PPA coal units) in Q4/03 varied by owner when compared to Q3/03. Overall Q1/03 unplanned outage was 4.6%, Q2/03 was 4.7% and Q3/03 was up at 6.0% and Q4/03 was 6.7%. Overall for 2003 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 2003. Two of the plant owners experienced higher unplanned outage rates in Q4/03 than in Q3/03, while one owner experienced a lower rate.

Table 4 - Outage for PPA Coal Units (% excluding planned outages)

	Q4/04	Q3/03	Q2/03	Q1/03	2003	2002	2001
Owner-A	7.8%	6.3%	1.4%	3.7%	4.9%	4.2%	3.2%
Owner-B	0.3%	2.5%	2.1%	1.1%	1.5%	0.5%	1.2%
Owner-C	7.8%	6.7%	6.8%	6.0%	5.7%	10.8%	8.8%
PPA weighted	6.7%	6.0%	4.8%	4.9%	4.9%	7.7%	6.3%

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 5** reports the MW weighted average target availability for each PPA coal fired portfolio and the actual availability achieved during 2001 - 2003[5]. On average, the PPA owners have reported higher actual availability than target availability.

Table 5 - 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
Owner-A	88%	94%	88%	92%	87%	92%
Owner-B	90%	95%	90%	97%	90%	94%
Owner-C	86%	86%	85%	87%	85%	88%
PPA weighted Average	87%	89%	87%	90%	87%	90%

In terms of overall availability, and compared with historical trends, Alberta's PPA units have performed well in 2003. The cycle of fewer planned outages as compared to unplanned outages that was seen in 2002 has trended back up, with a higher rate of planned outages being recorded in 2003.

As part of its 2003 project work, the MSA has undertaken further analysis of outages and derates at coal fired generating plants covered under the PPAs in Alberta.

[5] 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.

Three metrics based on regression analysis have been 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; and 3) An analysis of outage against the 30-day rolling average Pool price. The third 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

This 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 21 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. 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 21**, 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. This is a potentially troubling result, particularly in view of the MSA's concerns around information asymmetry.

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 to identify whether a longer-term systematic relationship existed. **Figure 22** reports the results of the same analysis for 2003.

For 2003, this relationship is not statistically significant on both an aggregate basis, and at the Owner level. This suggests that in 2003 there was little systematic relationship between forecast demand and unplanned outages. This is a more encouraging result – we will look to see a continuation of this outcome through 2004.

Figure 21 - 2002 Unplanned Outage vs. Day-Ahead Forecast System Demand

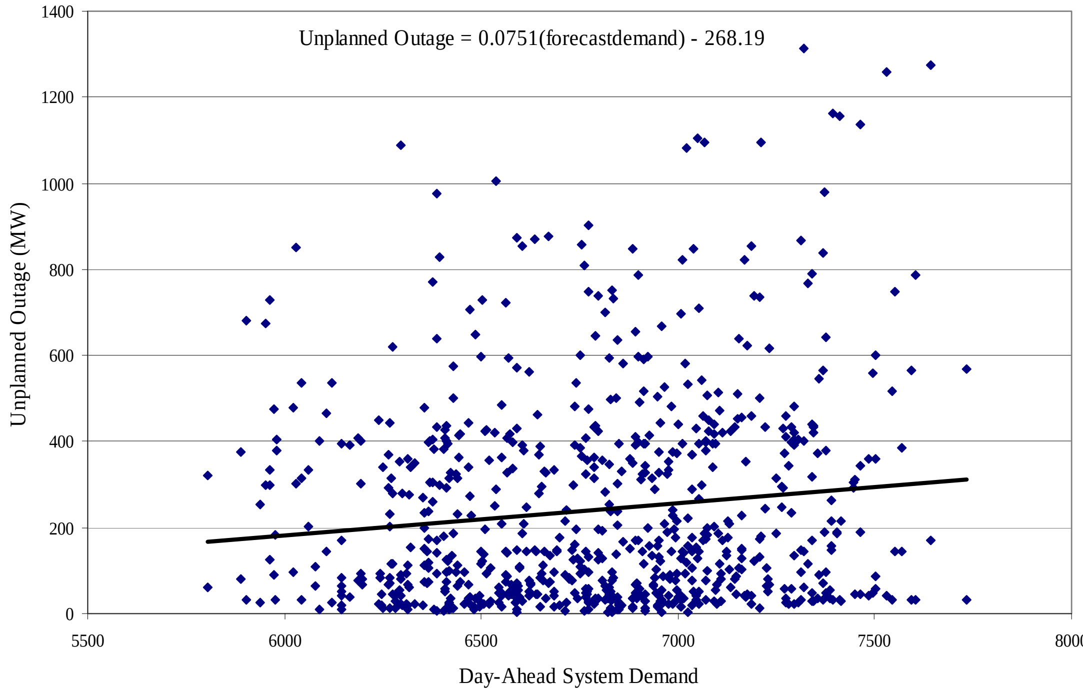
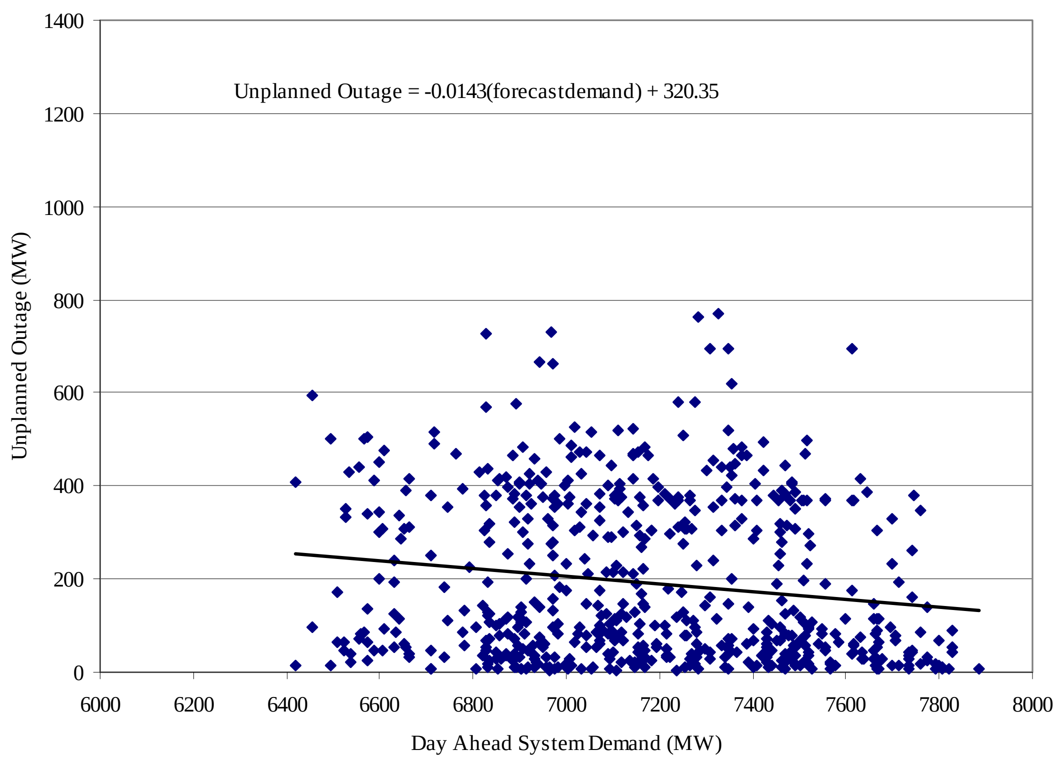


Figure 22 - 2003 Unplanned Outage vs. Day Ahead Forecast System Demand



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 23 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 24 illustrates this relationship for 2003. The slope of the relationship is similar for 2002 and 2003 although significant differences remain amongst the individual Owners' portfolios. In 2003, there were 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, and on only 5 occasions 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 23 - 2002 Unplanned Outage vs. Supply Cushion

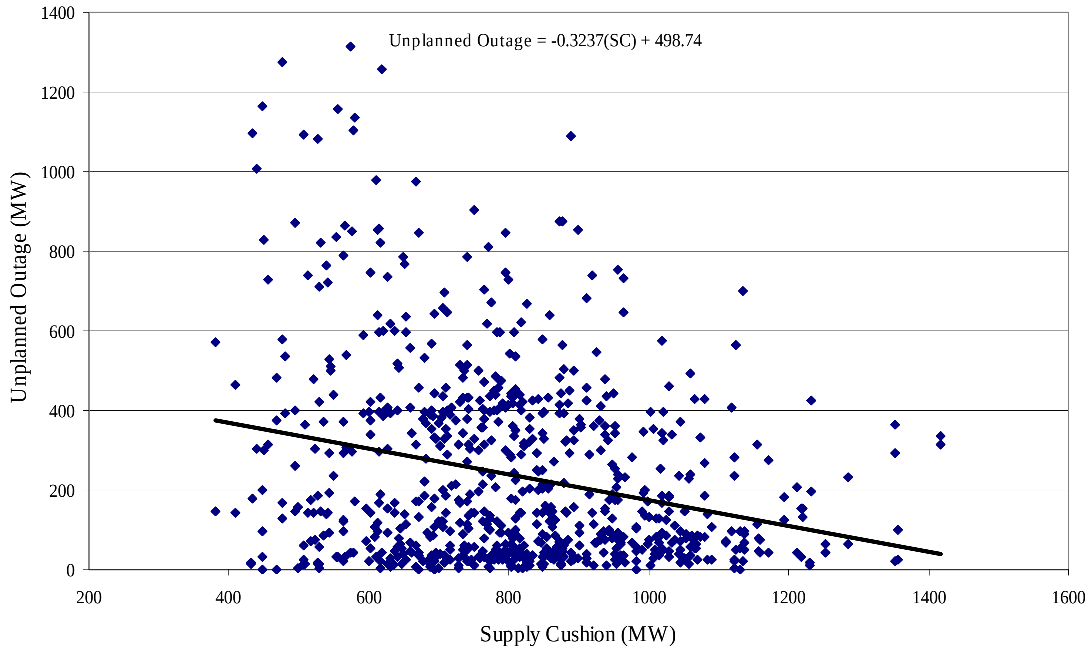
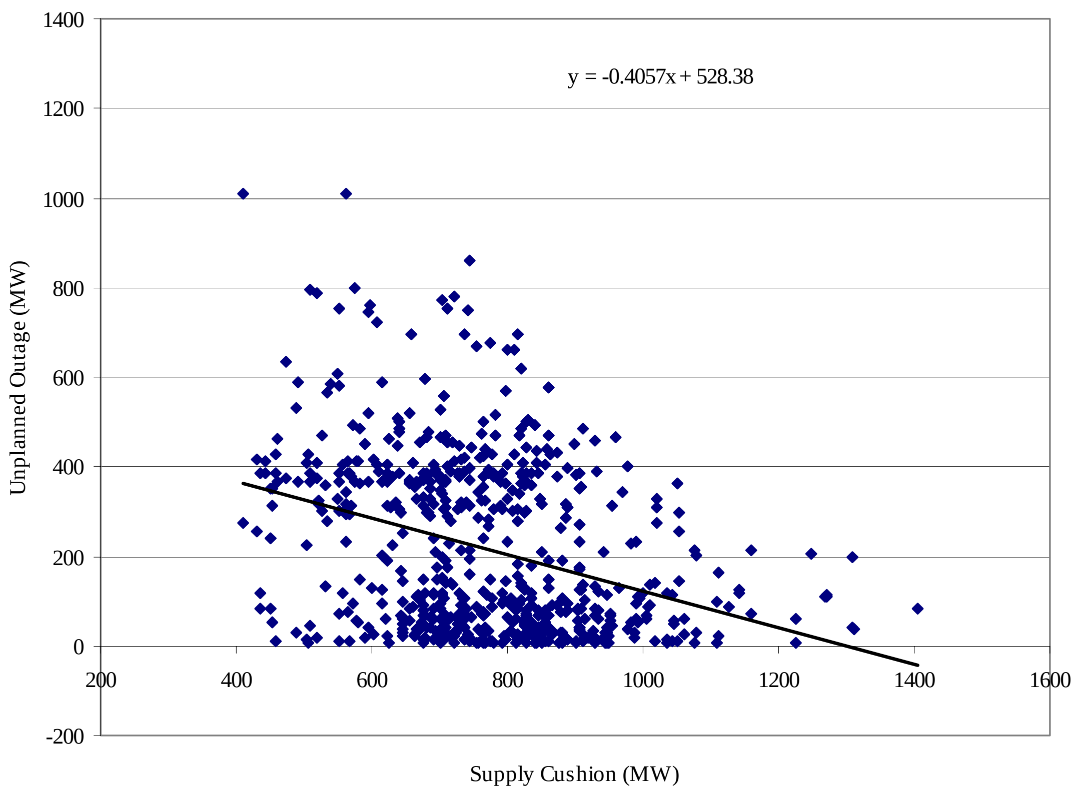


Figure 24 - 2003 Unplanned Outage vs. Supply Cushion



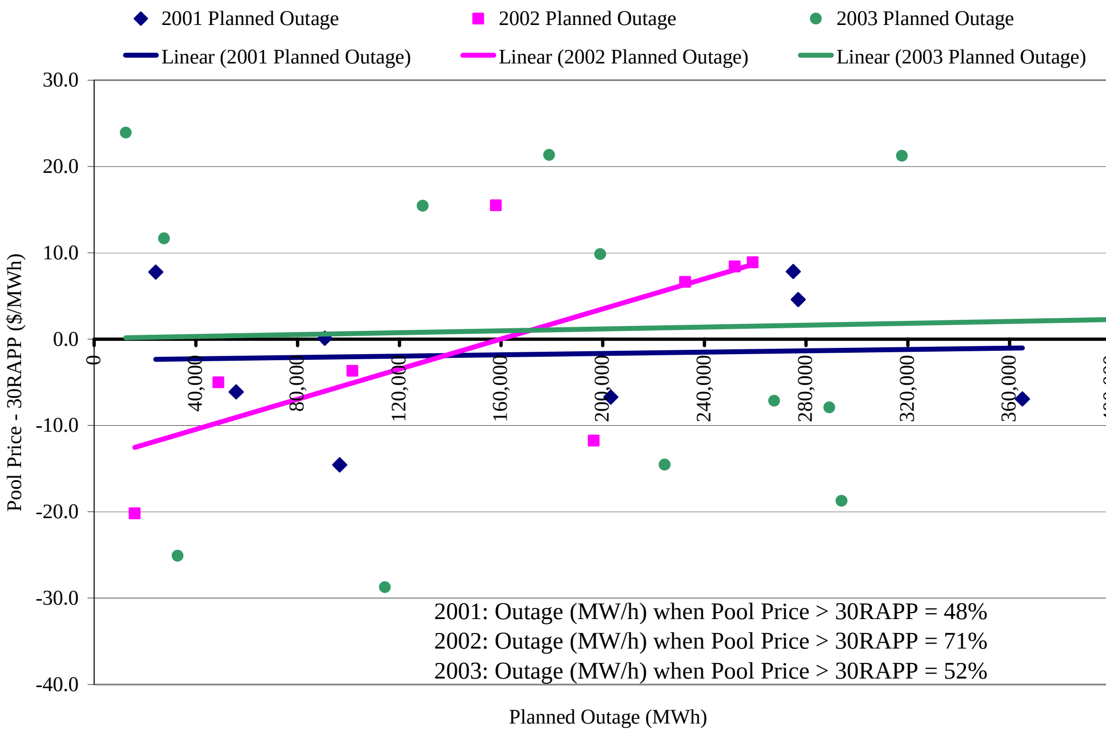
Planned Outages Versus the 30-Day Rolling Average Pool Price

The third 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 have an incentive 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.

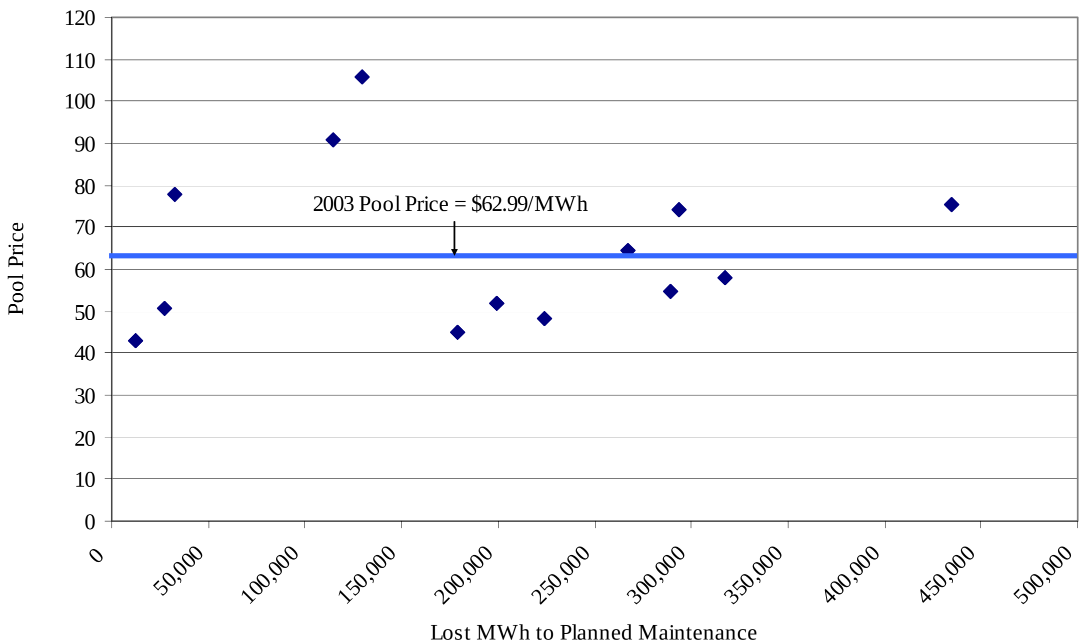
Figure 25 illustrates that the Owners were more successful at scheduling outages when the Pool price was greater than the 30RAPP in 2002 than in 2001. In 2003 the trend has shifted back to the trend seen in 2001. In 2003 the PPA Owners have scheduled half of the planned outages when the Pool price was 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.

Figure 25 - Pool Price – 30 Day RAPP Vs Planned Outages (Major Turnarounds), PPA Coal Units



In terms of the Pool price, 58% of major planned outages have occurred when prevailing prices over the course of the outage have been below the 2003 average Pool price of $62.99. **Figure 26** 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 26 - Major Turnarounds vs. Pool Price



Conclusions

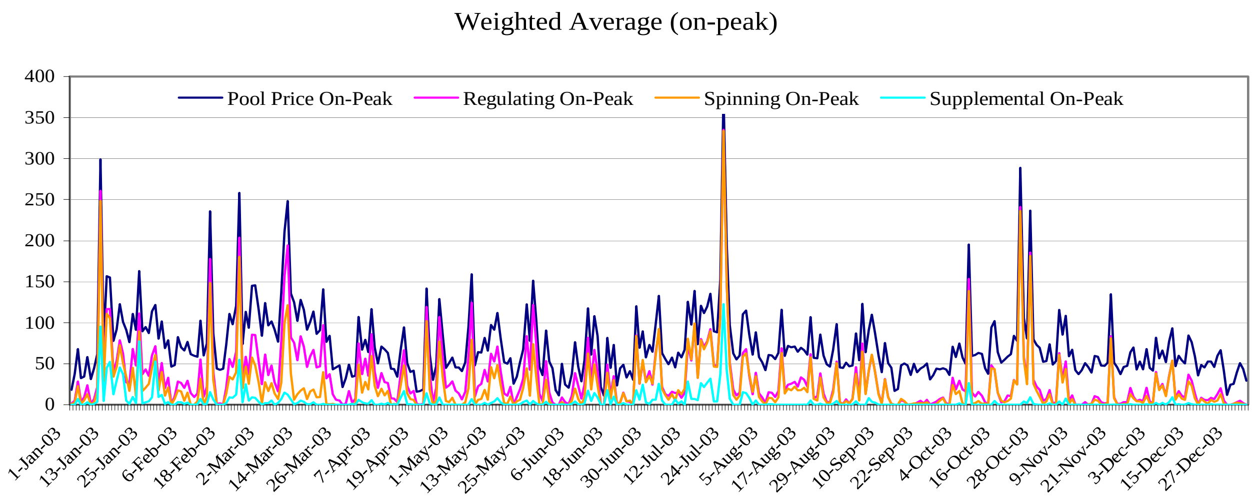
The overall availability of PPA units did not change significantly between 2002 and 2003. The outage rate averaged 10.4% for both years, down from 11% in 2001. In 2003 the composition of outages was more balance than in 2002; in 2003 planned outages represented over 50% of overall outages, compared with just 26% in 2002. Increased planned outage versus unplanned outages is considered beneficial in that planned outages are coordinated via the AESO and therefore create a lower potential for reliability issues. Furthermore, more planned outages reduce the probability of multiple forced outages occurring simultaneously, which can lead to market volatility as well as system issues.

An area of concern in 2002, which appears to have corrected itself in 2003 was a systematic positive relationship between unplanned outage and forecast demand. In 2003, the relationship between unplanned outage and forecast demand was negative, i.e., lower levels of unplanned outage were associated with higher levels of forecast system demand.

1.11 Ancillary Services Market

Figure 27 and **Table 6** show the weighted average delivered price of active ancillary service contracts through 2003, as traded on the Alberta Watt-Exchange (Watt-Ex). Delivered prices reflect the contract price participants would have actually received for selling active reserve services. This is only known after the service is delivered since active reserve contracts are traded at a differential to the Pool price prevailing when the reserve is actually delivered. Ancillary Services are procured by the AESO on both Watt-Ex and over the counter (OTC). There is no pre-set split between Watt-Ex and OTC procured volumes although historically the majority of procurement has taken place on Watt-Ex with only custom or shaping volumes procured OTC since contracts traded on Watt-Ex are standardized. In 2003 the majority of reserve volumes continued to be procured on Watt-Ex, however, as shown in **Figure 28**, the proportion of volumes procured OTC increased markedly in the second half of the year. With the AESO utilizing the OTC market to a more significant extent as part of its procurement strategy, the MSA is advocating for increased transparency in this area of the ancillary services market.

Figure 27 -Ancillary Services Clearing Prices, 2003



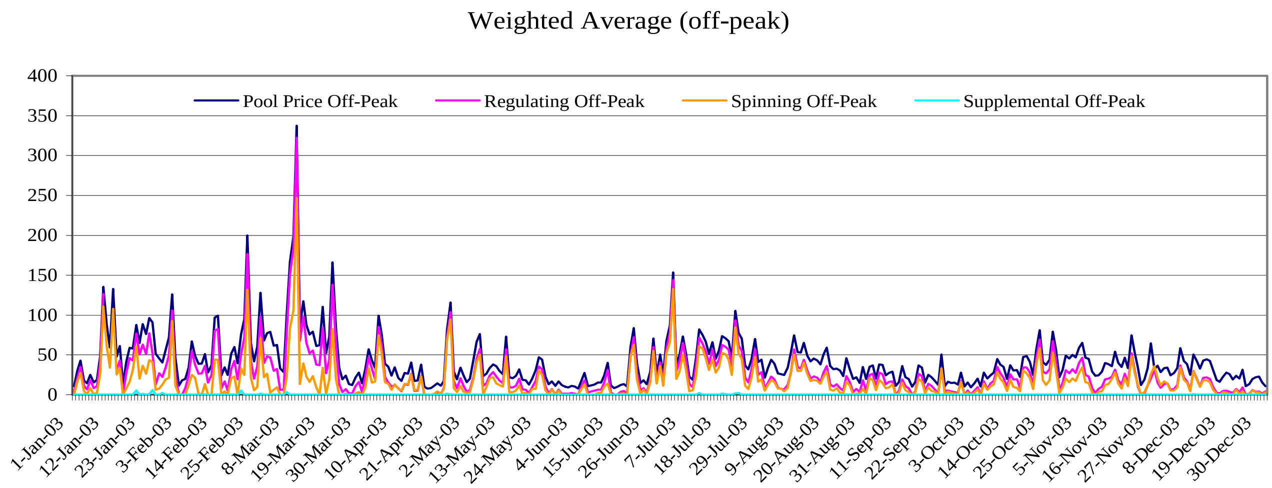
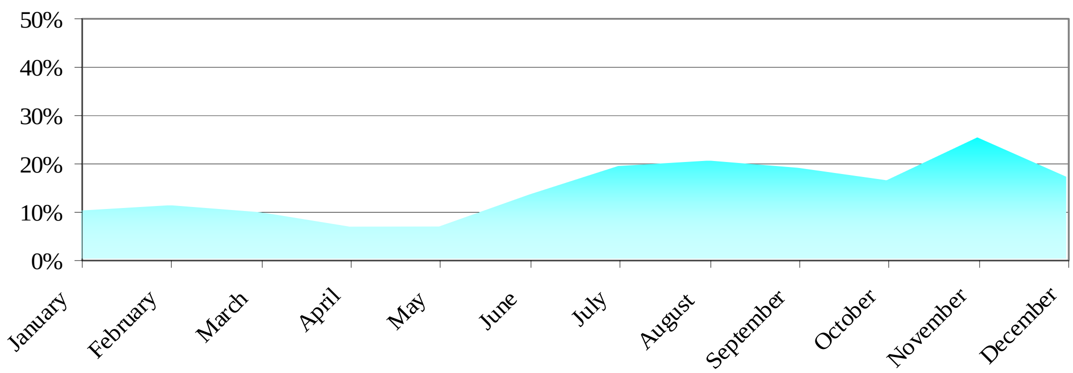


Table 6 - Monthly Average Clearing Prices, 2003

	Active Clearing Prices (avg on-peak)			Active Clearing Prices (avg off-peak)		
Month	**Reg**	**Spin**	**Supp**	**Reg**	**Spin**	**Supp**
Jan	49.16	39.17	17.01	39.06	29.06	0.49
Feb	42.88	28.89	6.45	39.28	19.25	0.24
Mar	50.47	18.98	2.45	56.49	25.73	0.12
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
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
Oct	36.43	30.65	1.64	22.97	16.46	0.00
Nov	12.24	9.74	0.44	20.30	16.56	0.00
Dec	12.89	10.42	0.74	10.08	8.36	0.04

Figure 28 - OTC Procurement as a Percentage of Total Procurement



Impact of Hydro

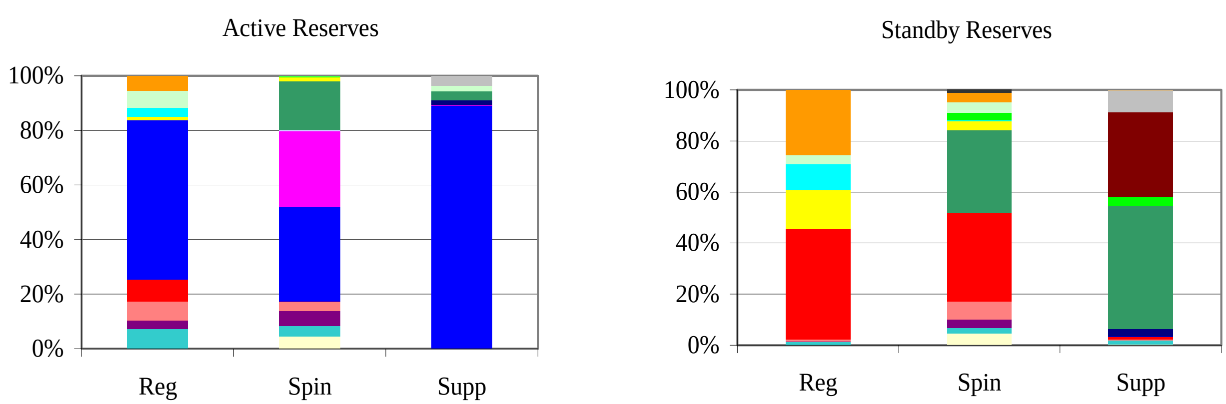
The hydro PPA is a financial PPA although the payments embedded in this agreement are based on hydro units supplying a notional volume of reserves to the market. If hydro provides volumes equal to its notional contract volumes, the hydro PPA is essentially a flow-through in that the revenue TAU receives for supplying reserves is equal to the revenue TAU must pay to the Balancing Pool. In some cases, the notional volume of supplemental reserves exceeds that which is required by the AESO. This places TAU in the position of being consistently short supplemental reserves and therefore having to pay more money to the balancing pool than they receive for providing supplemental reserves. As a result, TAU has an incentive to have a downward influence on the supplemental reserve trading index which then reduces TAU's payment to zero.

The hydro PPA continued to produce similar market outcomes in 2003 that were observed in the active supplemental reserve market through most of 2002. While this behaviour continued to influence the trading index for supplemental reserves, **Figure 27** shows that average clearing prices were positive for much of 2003 for on-peak contracts. Another important consideration is that other participants were still able to participate in this market. Anomalous market outcomes occurred with respect to other reserve products also in 2003 as a result of the hydro PPA although only periodically. A specific market event report was published by the MSA describing these events in detail. For more information, see http://www.albertamsa.ca/files/SpinningReserveMarketEventReport012304.pdf .

Market Share

Figure 29 shows the (anonymous) market share segmentation across the 6 competitively procured ancillary services markets in 2003. It can be seen that although there tends to be one participant with a relatively large market share in each of the individual reserve markets, there are numerous other competitors as well. Some market share concentration in the AS markets is inherent due to the hydro PPA. As well, certain other participants are more naturally suited to be providers of reserve services rather than energy for example certain of the MAP II strip contracts were specifically sold as ancillary services strips.

Figure 29 - Ancillary Services Market Share - 2003



AS Market Developments

As discussed in prior 2003 Quarterly Reports, a liability concern had been perceived by some market participants due to language in the new Electric Utilities Act (EUA). As expected, the EUB decision with respect to the liability module was rendered on December 18, 2003 in which the Board recommended that the Government of Alberta either amend the EUA or enact regulations pursuant to Section 94 of the Act to provide liability protection to Ancillary Service Providers. The target date for this change is July 1, 2004. For further information see Alberta Energy and Utilities Board | Decision 2003-109 .

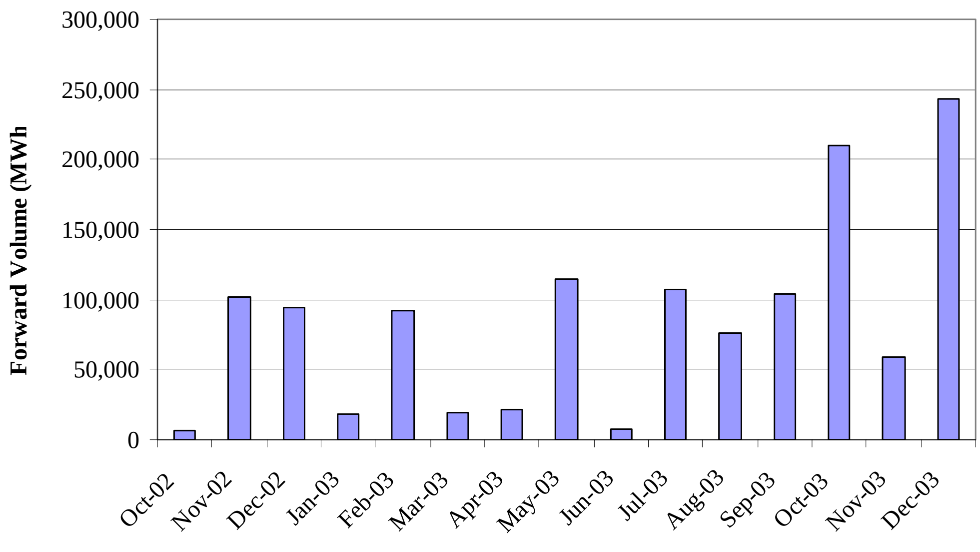
1.12 Forward Energy Markets

Forward energy trading occurs both on-screen via the Alberta Watt-Exchange (Watt-Ex) and the Natural Gas Exchange (NGX), as well as over the counter (OTC) in the broker market. Although there is not good outside visibility into volumes that are being transacted between parties in the broker market, it is believed that the majority of forward trade volume continues to take place OTC.

NGX launched trading in electricity financial swap contracts in April 2003 and although initial volumes have been thin, total deal volume was 574,760 MWh in Q4/03. NGX recently announced its acquisition by the TSX group of companies which is the operator of Canada's two national stock exchanges, and it will be interesting to observe if this event will impact trading activity on NGX.

In Q4/03, forward volumes on Watt-Ex increased to 511,588 MWh and as shown in **Figure 30**, this continued a trend of quarter over quarter increases through 2003. Despite this trend, forward volumes for the year were about one quarter of forward volumes traded in 2002.

Figure 30 - Watt-Ex Forward Energy Volumes



Forward market liquidity (or lack thereof) continues to be a concern of the MSA as forward volumes transacted on Watt-Ex and NGX together only represent on average less than 5% of energy traded through the AESO. Wide bid offer spreads in the broker market also underscore this lack of liquidity. It is the view of the MSA that information asymmetry in the marketplace is a key factor producing this market outcome. In 2004, the MSA will increase its focus on improving the fairness of the market with respect to information asymmetry, which should enhance forward market liquidity.

2 REVIEW OF THE RETAIL MARKET

2.1 Regulatory Proceedings

Throughout 2003, the MSA continued its regular watch of proceedings before the Alberta Energy and Utilities Board (EUB) and other regulatory bodies. The purpose of this is to be aware of matters relevant to the broad mandate of the MSA

During October and November, the MSA and the EUB dealt with 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 applications were made to the EUB 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 exemption(s) 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. In order to handle the applications efficiently, the MSA and EUB established a process whereby a joint record was developed and maintained; however, the decision of each regulator was handled independently, though based upon the joint record.

The MSA decision was issued in November and is available on the MSA website along with the related application materials (#2003-00101). In its decision, the MSA approved the sharing of certain information which would be masked to ensure that an individual customer's information could not be identified; various conditions were attached to the approval in this regard. The MSA declined the further approval requested in relation to non-masked information.

The EUB reached an essentially similar outcome in its decision.

2.2 Code of Conduct

Compliance plans and audit plans are required from owners and their affiliated retailers; the plans must be approved by the MSA before they are effective. This is a significant change from the approach taken by the previous regulation in this regard (previously only the owner was required to file a compliance plan, and there was no requirement for approval of the plan).

Further, the Code requires that all owners provide an annual compliance report to the MSA, regardless of whether the owner has an affiliated retailer. The annual compliance reports are made due January 30 of each year, for the preceding calendar year.

The MSA may at its discretion publish all or part of the compliance plans and annual compliance reports received from owners and affiliated retailers.

In accordance with its responsibilities under the Code, the MSA undertook a series of meetings with stakeholders in preparation for the review and approval of compliance plans required under the new regulation. The MSA began reviewing draft compliance plans in November, and this work continues.

In December, the MSA issued interim approvals for certain parties in respect of their draft compliance plans. The interim approvals allow the parties to meet the requirements of the Code and undertake retail activities while work continues toward full compliance plan approval. The interim approvals carry terms and conditions, including a February 29, 2004 expiry date.

Preliminary discussions around audit plans also commenced in 2003, and remain ongoing, in preparation for Code audits which will be required for certain parties in 2004. The audits are due to be completed by March 31, 2004. The MSA expects to report on the results of the audits during Q2.

In respect of the scope of the 2003 audits, the MSA advised the parties involved that the audits would test for compliance with the Code by owners and affiliated retailers for the period June 1 to December 31, 2003 inclusive. Further, the audits would not be required to test for adherence to compliance plans during the year. The reason for this approach for 2003 is that the new Code came into effect June 1; the previous regulation was substantially different, therefore making it very difficult to design useful testing. In addition, the previous regulation did not require compliance plans from affiliated retailers, and the compliance plans filed by the owners were based upon the old regulation.

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.

Enmax, the market participant engaging in the negative option practice, agreed to stop doing so, and gave undertakings to the MSA in this regard.

2.3 Load Settlement Monitoring & Enforcement

The AESO made changes to the Settlement System Code (AESO rules) in respect of compliance and enforcement, effective September 30, 2003. The specific changes and related materials can be seen on the AESO website.

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. In addition, the MSA will be monitoring other indicators around the operation of load settlement, and plans to report on these indicators in its quarterly reporting, beginning Q1 2004.

2.4 Retail Market Metrics

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

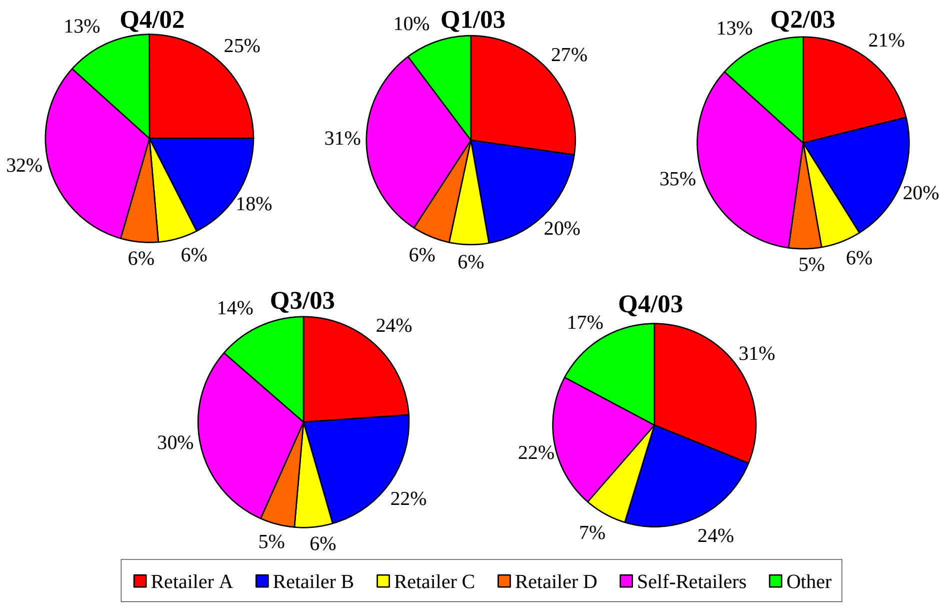
- Number of active retailers
- Retailer entry and exit from the market
- Market share (with respect to load) of retailers by customer class
- Customer switching off the regulated rate option to a competitive contract by RRO[6] eligible customer class.

Five quarters worth of data has now been collected which allows for a reasonable evaluation of competitive activity in the retail market over the last year.

As of December 31, 2003 there were 103 active retailers in the Alberta electricity market, 71 of which are self-retailers. Although this is the same number of retailers that were active at the end of Q3/03, 3 retailers entered and 3 retailers exited the market during the last quarter. Since the end of 2002, 15 new retailers have entered the market while 11 retailers have exited the market. The total number of retailers in the market peaked in Q2/03 at 106 active retailers. 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.

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

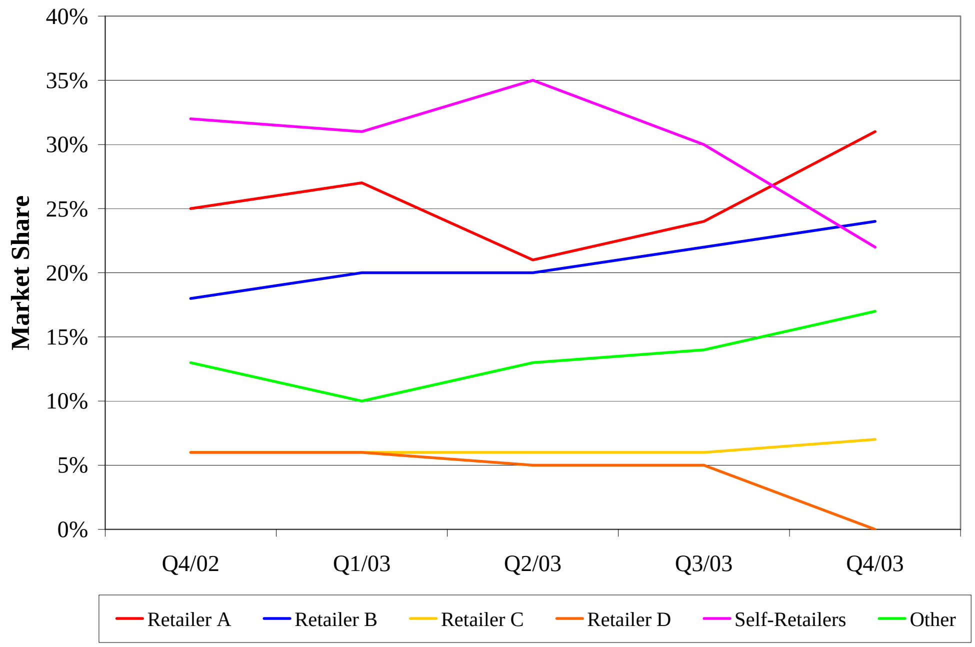
Figure 31 - Overall Market Share of Retailers by Load



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

Figure 31 shows the overall (all classes) market share of retailers for the last five quarters. The figure shows that up until Q4/03 there have consistently been 4 retailers with market shares of at least 5%. In Q4/03 this number dropped to 3; however, the market share of "other" retailers has increased accordingly to account for the one retailer dropping below the 5% market share threshold. **Figure 32** shows the progression of market shares over the past year.

Figure 32 - Progression of Retailer Market Shares



The figure emphasizes the change in trend of retail market shares in Q4/03. In past quarters the overall market share of the three largest retailers in the province had been decreasing. In Q4/03 the combined market share of retailers A, B and C jumped to 62% from an average of 50% over the previous four quarters. It appears that the increase in market share of these large retailers has come at the expense of self-retailers. Total load served by self retailers decreased from 3.8 million MWh in Q4/02 to only 2.0 million MWh in Q4/03. Overall the figure indicates movement of load between various retailers which is viewed as a healthy sign of competition. Movement away from the dominant retailers is intuitively more encouraging, but the observed movement back to the largest retailers could indicate more competitive offers being made by these incumbents in order to retain (or increase) their market shares.

Figure 33 - Q4/03 Market Share of Retailers by Customer Class

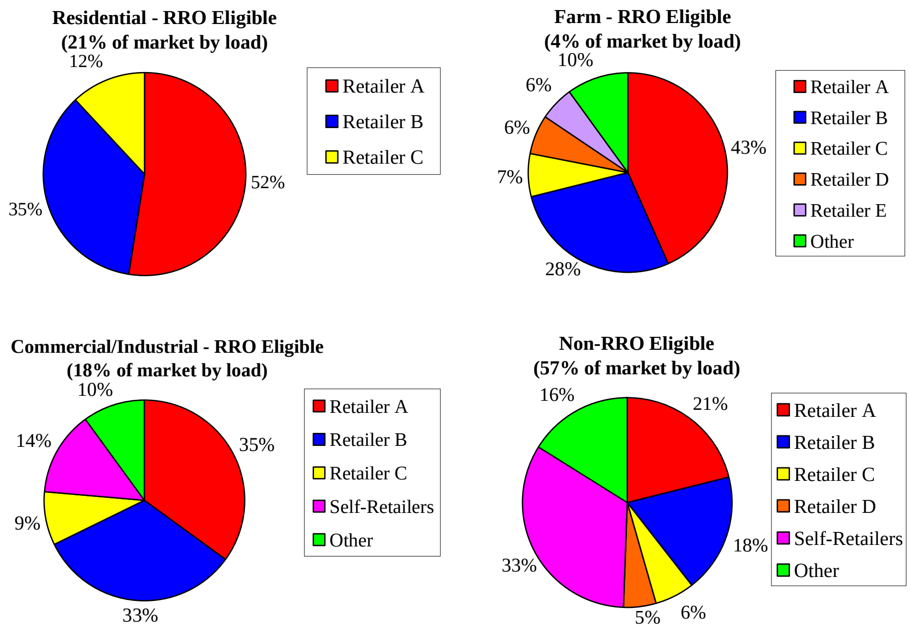
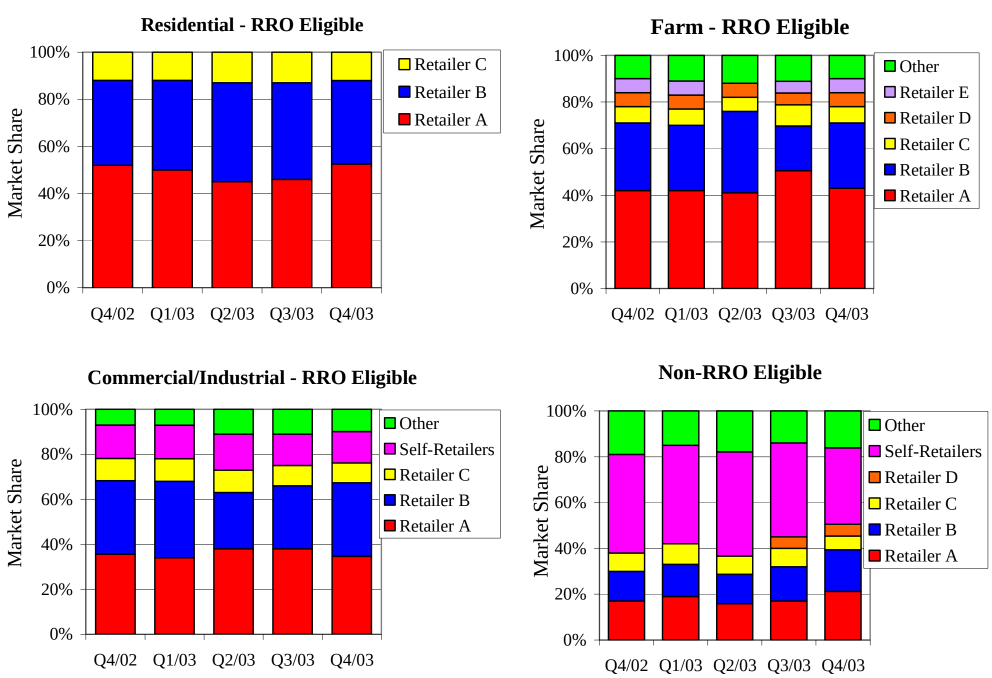


Figure 34 - Progression of Retailer Market Share by Customer Class



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

Figure 33 shows retailer market share by customer class for Q4/03, and **Figure 34** shows the progression of market share by customer class since Q4/02.

Market shares of the three dominant retailers in the Residential – RRO Eligible class have not materially changed over the past quarter. In fact, Q4/02 and Q4/03 market shares of these three retailers are identical. There was a slight increase in Retailer B's market share during Q1, Q2 and Q3/03 which may indicate higher seasonal electricity use by this retailer's customers.

In the Farm – RRO Eligible category, market shares have remained fairly static since Q4/02. Much like the residential category, market shares of all retailers identified (Retailers A-E) are within 1% today of what they were a year ago. The most notable variations occurred in Q2 and Q3/03 when market shares of Retailer B and Retailer A increased respectively. This is likely a seasonal effect and may be due to increased consumption by irrigation customers in the summer months.

Competition appears to have increased slightly over the last year in the Commercial/Industrial – RRO Eligible customer class as the market share of "other" retailers has increased from 7% to 10%. During 2003, more options became available to small commercial customers as the RRO was expected to expire at the end of 2003. Despite the apparent increase in competition, the market shares of the two dominant retailers in this category have hardly changed from where they were at the end of 2002.

The most significant changes in market share distribution have been in the Non-RRO Eligible category. A year ago there were only three retailers with market shares greater than 5%. Four retailers now hold market shares greater than 5%, suggesting an increase in competition in this sector. The market share of self-retailers decreased once again this quarter. In Q4/03 only 33% of non-RRO eligible load can be attributed to self retailers while the market share for the same category in Q4/02 was 43%. The changes in market share statistics through time show that the retail market in this sector is dynamic and compared to the other market sectors, there is more competition in the Non-RRO Eligible category.

The overall progression of customers off of RRO to competitive electricity contracts continues to improve, albeit very gradually. As of December 31, 2003, 7.4% of all RRO eligible customers have chosen to sign a competitive contract with a retailer, as shown in **Figure 35**. This represents a 0.3% increase since the end of Q3/03 and a 1.9% increase since the end of Q4/02.

Figure 35 - Progression of RRO Eligible Sites Switching Off RRO

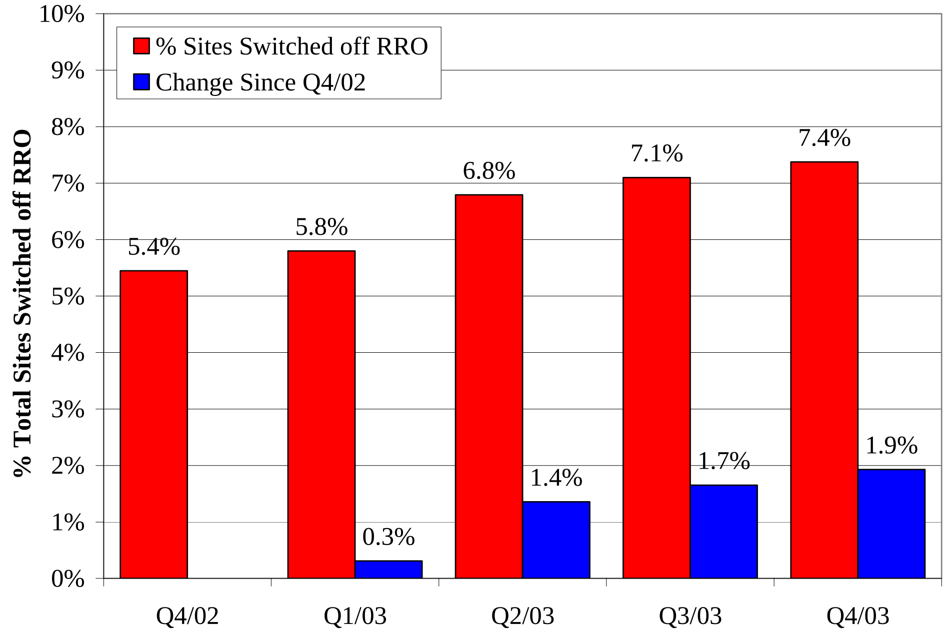


Figure 36 - Progression of RRO Eligible Sites Switching Off RRO by Customer Type

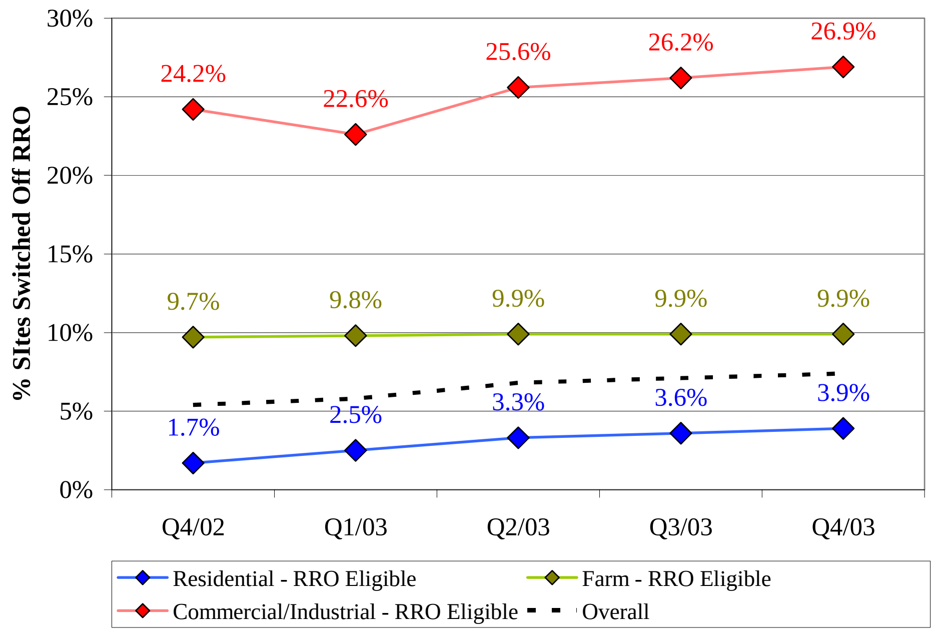


Figure 35 shows the progression of RRO eligible sites switching off RRO for the last five quarters by customer type. The number of sites switching off RRO has continued to increase in every category since Q4/02. Switching rates have been increasing at a steady pace over the last two quarters in the residential and small commercial categories. Switching has

shown little change in the farm category but was up slightly in Q4/03 as compared to the same period last year. Although the progression is quite slow, it shows that the Alberta population is becoming more accepting of the idea of a competitive electricity market.

During Q4/03, a change in policy pushed back the deadline for Commercial/Industrial – RRO Eligible customers to choose a competitive contract or be subject to Pool price flow-through from the end of 2003 to July 1, 2006. Customers in this category who have not signed competitive contracts will remain on RRO for this extended period. As such, the large increase in switching off RRO that was expected for Q4/03 was not observed.

3 MARKET ISSUES

3.1 Information Sharing

In the course of the MSA's monitoring and surveillance activities, it became apparent that there are a number of information-sharing issues warranting a comprehensive approach. Of particular concern was the trading on outage and derate information prior to that information being made public. The MSA commenced a major initiative during 2003 concerning the development of a general framework to guide information-sharing activities in the Alberta market. This initiative is expected to be fully implemented during 2004.

3.2 Spinning Reserves Issue

In early November, TransAlta Energy Marketing Corp., a subsidiary of TransAlta Utilities (TAU), initiated a trading behaviour in the active spinning reserve market which was similar to its trading practice in the active supplemental reserve market in which TAU prices its offers at a highly negative differential to Pool price. This had a noticeable influence on the market index for active spinning reserves and was motivated by TAU being unable to supply their full obligation under the Hydro PPA. The benefit to TAU is that the behaviour minimizes the cost of being short of reserves under provisions of the Hydro PPA. Although there was no direct harm to other sellers of reserve products other than being crowded out of the market on certain days from the ability to sell certain reserve contracts, the MSA viewed the behaviour as aberrant since no other market participant would have an incentive to trade similarly. As well, the MSA viewed this behaviour as having an undue and undesirable influence on a market index. The MSA published a market event report which describes this issue in detail in order that all ancillary services market participants may better understand these market outcomes. The MSA continues to work with various parties to facilitate a long term solution to this issue. For further detail see http://www.albertamsa.ca/files/SpinningReserveMarketEventReport012304.pdf .

3.3 Negative Option Customer Consent

The MSA was aware of concerns around use of so called "negative option" consent practices, in which notice is 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. In respect of the Code of Conduct, 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. The MSA stipulated that written or electronic consent would be the standard required under the Code, and would expect this to be addressed in the compliance plans of the various parties subject to the Code. Enmax, the market participant engaging in the negative option practice, agreed to stop doing so and gave undertakings to the MSA in this regard.

3.4 Regulating Reserve Issue

As a result of concerns expressed by a reserve market participant, the MSA conducted an informal investigation into a fundamental change in the active regulating reserves market. The MSA reviewed the pricing strategy of reserve providers and whether reserve providers were being treated in an equitable manner. The MSA found the pricing behaviour of regulating reserve providers to be consistent with the behaviour that would be expected in a competitive market. Further, the MSA found no evidence to indicate that reserve providers were not being treated in an equitable manner.

3.5 Dispatch Compliance

The Alberta wholesale market price is set on a minute-by-minute basis (SMP) and the hourly average of these values is the Pool price. To be able to set price, a unit must be capable of responding to dispatch instructions from the System Controller (SC). In Q4/03, the MSA examined the monitoring and enforcement of the AESO rules pertaining to dispatch compliance by generators. The rules were introduced in late 2000 and the MSA's review indicated that, overall, compliance by generators was good. However, the review concluded that the rules themselves should be reconsidered and possibly made tighter. Also, the few generators who do exceed the existing generous limits should have their energy payments for such over-generation withheld.

3.6 Review of Aggregator Role

The MSA received concerns with regard to the transparency of the Balancing Pool aggregator function. The aggregator function combines the strip offers associated with the derivative contracts sold from the Sheerness and Genesee generating stations, into one set of offers for each generating asset. The MSA undertook a review of the aggregator role and applicable rules and published a synopsis of its findings. This review concluded that the aggregator function is a useful and appropriate mechanism to facilitate offers related to the strip contracts, and further, that it is operating fairly.

4 OTHER MSA ACTIVITIES

4.1 MSA Move

In April 2003, as a result of industry restructuring due to the new *Electric Utilities Act*, the MSA moved to physically separate premises from the AESO and the MSA was established as a separate corporate entity. The MSA remains a not for profit agency funded though the AESO trading charge.

4.2 EISG Activities

The Energy Intermarket Surveillance Group (EISG) is an international association of energy market surveillance groups. This group provides opportunities for the MSA to meet and discuss matters of mutual interest and concern with similar groups in other jurisdictions. Despite the many different market structures that exist, the types of issues encountered by the market monitors are often quite similar in nature. This group meets twice annually and continues to be an important affiliation for the MSA.

4.3 Stakeholder Meetings

The MSA continued to hold its twice yearly stakeholder meetings in Calgary and Edmonton. These meetings are a forum for the MSA to keep market stakeholders abreast of the activities and outlook of the MSA as well as an opportunity for market participants to voice their questions or concerns regarding the market, directly to the MSA. Notices of these meetings are posted in advance on the MSA website and presentation materials are also posted to the website shortly after the meetings have been held.

4.4 Appointment of MSA

Martin Merritt was appointed as MSA effective July 1, 2003. Martin succeeds Tom Cumming whose appointment expired. Martin comes from a diverse energy and commodities background, and most recently was VP of structured power for a major Calgary based energy marketing firm.