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MSA Report

2006 Year in Review

28 March, 2007

Market Surveillance Administrator

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EXECUTIVE SUMMARY

Markets depend on signals. Since the first steps in restructuring Alberta's electricity market in 1996 our market has been producing an hourly price signal. In January 2001 the modern era of our market began, with private, for profit investors paying over $2.0 billion for the privilege of controlling the legacy generation assets built by the previously regulated utilities.

Over the ensuing years the province has moved from capacity deficit to surfeit and now back toward deficit, a sequence that has been reflected in the fluxing of the price signal and subsequently rational responses by market participants. Today, as a booming economy ushers in a new period of inevitably tighter capacity, several critical questions confront us:

- Will Albertans understand the need for scarcity pricing and be patient enough to wait for it to do its work?
- In a market with growing concentration, how do we ensure that appropriate and necessary scarcity pricing does not turn into monopoly rent?
- How will investors respond to the current price signals?

At the heart of these questions are the very premises of competitive markets and the role of market surveillance.

The first half of 2006 saw average prices of $55.23 per MWh however, this summer and fall produced several periods of record high daily average pool prices which pushed the annual average price to $80.79 per MWh. Capacity was indeed scarce at times as a result of a combination of planned and unplanned outages. While prices were not in the MSA's view out of line with what might be expected during a period of tight supply, the line between necessary and appropriate scarcity rent and market power derived monopoly rent is a fine one.

It is important to understand that high prices from time to time during periods of genuine scarcity are normal and a necessary feature of our market design. Higher prices ration demand and help to ensure reliability. They pay for the many hours that are well below the full cost of production and they signal the need for and willingness to pay for new generation. When generation supply is scarce as it will likely be more often over the next few years, the MSA has a challenging job. On one hand it is imperative that we stay out of the way of the price signal doing what it properly needs to do: signal and pay for scarcity as our long term adequacy depends on the integrity of the "build signal". On the other hand, we must be watchful for wealth transfers that are the product of anti-competitive behaviour. Such behaviour becomes increasingly possible when genuine scarcity coincides with growing supply side concentration.

One of the success stories of the first ten years of restructuring has been the market's ability to attract new generation, most of it built by already large incumbents. Market concentration has been growing steadily as incumbents build and as they buy up the legacy PPA's either at auction from the Balancing Pool or on the secondary market.

There are presently no limits on participant size in our market and our pool rules are focused primarily on operational rather than competitive requirements. We have come to the point where competitiveness requires more clear guidance on permissible conduct and or size. Resolution of this uncertainty will be welcomed by current participants, by prospective investors and by the MSA alike.

We reported in the third quarter that the trailing twelve month price signal appeared to be indicating viable economics for at least peaking generation following several years where the signal to investors had clearly and appropriately been "don't build". Fourth-quarter power prices have been both higher and more volatile while fuel costs have continued to be soft, improving the profitability of all types of generation but peaking units in particular. The assertion that the economic signal is there was endorsed by Epcor and TransAlta's recent announcement that they will be commencing construction on the Keephills 3 generating station. While the announcement is a welcome and positive sign, we will need approximately three more like it to meet load growth between now and its anticipated commissioning date.

Many factors bear on the decision to invest shareholder capital in new facilities. Notwithstanding the clarity of the price signal other signals may be confounding. These confounding signals include transmission bottlenecks, regulatory uncertainty and a forward market whose prices may not yet support new generation. In addition, the growing prevalence of joint venture projects, which allow the sharing of risk and financing, may reduce the inclination of an individual merchant plant developer to jump in first as a matter of competitive strategy.

If our market design is to ensure long-term adequacy of supply for Albertans, we must resolve the issues that confound the investment signal. Simultaneously enhancing the competitiveness of an increasingly concentrated market will be particularly challenging for policy makers, participants and the MSA.

1 FEATURED WHOLESALE MARKET DEVELOPMENTS DURING 2006

1.1 Market Prices

After a volatile and high priced fourth quarter in 2005, Pool prices moderated significantly in early 2006 through to the end of June. Pool price for the first six months of 2006 averaged $55.23/MWh. Periods of outage driven scarcity of supply in summer and fall drove new record average daily Pool prices which increased the yearly average price for 2006 to $80.79/MWh – the highest yearly average since 2000.

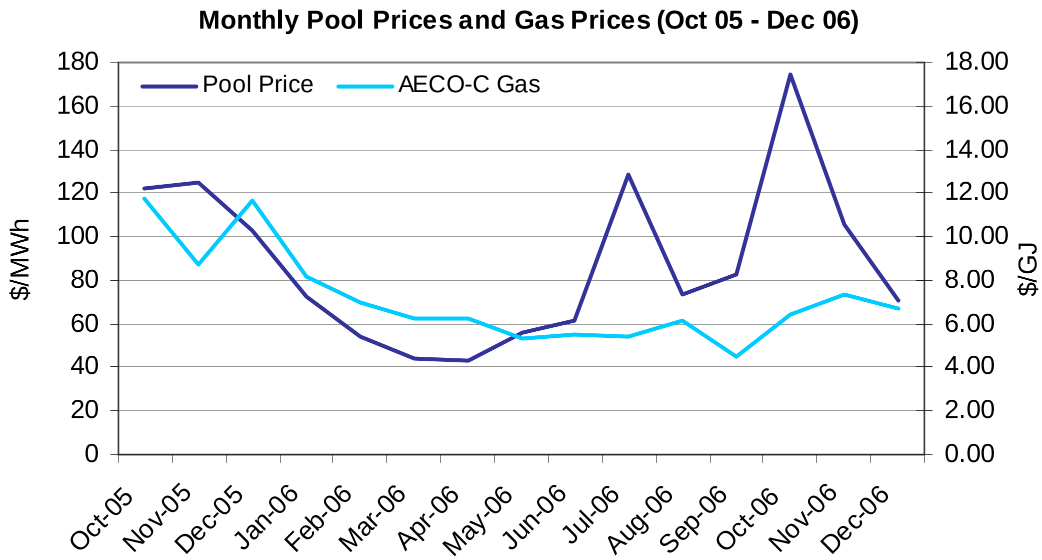
Supply scarcity events had a significant role in higher average Pool prices for 2006, particularly July and October[1] – the two highest priced months averaging $128.23/MWh and $174.09/MWh respectively. Outage events on July 24, 2006 are noteworthy as they resulted in a new record high daily average Pool price of $526/MWh. With three coal plants offline on planned maintenance, a transmission line fault caused Sheerness units 1 and 2 to trip offline. The severe reduction in supply resulted in Pool price reaching the price cap of $1000/MWh and remaining there for 9 consecutive hours. A subsequent Alberta-BC intertie trip which was caused by a lightning strike, necessitated the shedding of 400 MW of firm load for a period of less than one hour. This was the first firm load shedding event since 1998.

The record daily average Pool price set on July 24th was broken on October 4th ($533.87/MWh) and again on October 5th ($576.11/MWh) when supply scarcity forced wholesale market prices to very high levels. Over 1500 MW of coal generation was offline during this interval due to planned and forced outages. As well, intertie constraints played a role as the Saskatchewan intertie was essentially out of service and constraints in US-BC interconnection resulted in a reduction in import volumes from BC. No shedding of firm load occurred as a result of the tight market conditions experienced in early October.

1.2 Implied Market Heat Rate

The average implied market heat rate rose sharply in 2006 to 13.9 GJ/MWh after four consecutive year-over-year declines. While this increase is significant, softening gas prices through 2006 amplified the change. Looking at a graph of Pool price and gas price, it is apparent where the two curves de-coupled substantially during the second half of 2006 which underscores that higher Pool prices were not driven by gas but by other variables, particularly supply scarcity.

[1] The MSA published event reports during 2006 which analyzed the market circumstances of July and October in further detail.



1.3 Load Growth versus Supply Growth

Load increased by a significant 4.7 percent on a year-over-year basis or approximately 350 MW on average. Peak demand, on the other hand, did not show as substantial an increase as had been expected by the market operator and others. In 2006 peak demand was 9,661 MW – a modest 0.9 percent increase relative to 2005. This can be attributed to the unseasonably mild weather through the December peak demand period.

On the supply side, additions in 2006 were modest, with the commissioning of 150 MW of new wind generation as well as minor additions related to oil sands development. On the other hand, 90 MW of gas generation left the system with Atco's decommissioning of Rainbow units 1, 2, and 3 at the end of 2006.

Unprecedented provincial economic growth in the order of 6 percent was a key driver of the growth in system load observed in 2006. Robust economic growth is expected to continue in 2007 at a pace of four to five percent. Continued system load growth in light of limited new generation will continue to stress the system. Outages will have a greater impact on market price as the supply cushion becomes leaner.

1.4 Concentration and Size-based Behaviour

With the elimination of holding restrictions, and subsequent secondary market transactions including the sale of the Battle River and Sheerness PPAs, and the tolling agreement for Calpine Energy Trust's 250 MW gas plant, the largest generators have grown larger. An auction of the Genesee PPA could further alter the picture significantly. The MSA devoted considerable effort during 2006 to examining the mechanisms, possible consequences, and means of assuring a fair, efficient and openly competitive market in light of growing concentration. This included the development of various new tools to better analyze and assess market behaviour.

In early 2006, the MSA observed that a large participant had implemented a persistent "shelf strategy" in which substantial energy volumes were offered within a very small price band with the inferred goal of managing Pool price. The MSA views artificial "shelves" in the supply curve as a source of distortion to market price and therefore harmful to price fidelity. After analyzing this behaviour, the MSA voiced its concerns about this particular size-based strategy. The "shelf strategy" has subsequently abated; however, on occasion the MSA still has concerns about the lack of competition in marginal price setting. It appears that a number of participants that historically competed at the margin have stepped back in 2006. As a result, one participant was left to set the price an inordinate amount of the time.

In late 2006, in order to provide the basis for discussions with industry and the provincial Government over market concentration issues, the MSA published a study entitled Market Concentration Metrics. On an offer control basis, market concentration as represented by the Herfindahl-Hershman Index (HHI), has entered a range that other competition agencies such as FERC, and the U.S. Department of Justice describe as moderately concentrated. Pivotal supplier tests such as Residual Supplier Index (RSI) and other metrics reinforce the MSA's concern.

1.5 Net Revenues

The MSA has historically performed a directional analysis of returns for new generation in its quarterly or annual reports. Our estimate of return on capital for a theoretical investment in new coal, gas peaking, and combined cycle generation indicated that for the second year in a row, coal generation appeared economic. Peaking gas generation and combined cycle also appeared to be economic on the basis of 2006 returns, but not in the prior two years. While these results are intended as directional in nature, they indicated substantially better imputed returns in 2006.

1.6 Forced Outages

Over the second half of 2006, the market observed an increased occurrence of price excursions. Analyses of the more significant price events revealed that one of the main drivers was the amount of coal capacity off line due to forced outages and derates. When reporting on the October price event, the MSA indicated that it would undertake some assessment work on forced outages and derates to determine if there was a substantive change in the pattern of forced outages of the coal units.

A comparison of forced outages over a recent 12-month period (Nov 1, 2005 – Oct 31, 2006) with prior years indicated that high levels of forced outages were more frequent both in terms of the number of units and the volume of energy. While results for the recent period were elevated, the analysis indicated they were within historical bounds.

An analysis of the clustering of forced outages of the PPA units around weekends revealed that the average number of units on forced outages was statistically higher on weekends than weekdays. This is likely due to the design of the PPA's whereby PPA Owners are required to make lower availability payments to Buyers if forced outages occur on weekends as opposed to weekdays. These payments are based on 30-day rolling average Pool prices and are calculated separately for on- and off-peak periods. The impact of weekend clustering of forced outages is generally offset by the fact that lower loads occur on weekends than weekdays. However, it causes higher occurrences of multi-unit outages and outages at certain megawatt levels. Also, should it become apparent that a particular weekend is going to be tight, PPA Owners are not motivated to move the outage as the 30-day rolling average Pool price remains as the price signal and will be low.

A Monte Carlo simulation analysis suggested that forced outage events among different units were not independent. The Monte Carlo simulation also showed clustering of forced outages at certain megawatt levels. Assuming "independence" of forced outages is likely to underestimate the occurrences of multi-unit forced outages and those at certain megawatt levels.

The fact that there were higher occurrences of observed multi-unit outages than those simulated by the Monte Carlo process suggests possible positive correlations in forced outages among different units. An analysis of correlations of forced outages among different units at the same plant showed small but statistically significant positive correlations. The correlations are likely caused by constraints of resources (e.g. a common cooling pond) shared by different units in the same station. The correlations indicate that the operating status of certain units may contain information about the operating status of other units at the same site. Such information may help system reliability planning to better estimate the occurrences of multi-unit outages.

The conclusion drawn from the work described above is that there does not appear to be a structural shift upwards in the forced outages of coal units. Overall, the availability of the PPA coal units exceeded target availability for 2006. Similarly, the amount of forced outage in 2006 was not exceptional. It is the coincidence of a number of planned and forced outages that can put upward pressure on market prices. The MSA will continue to monitor all outages of units in the system.

2 FEATURED RETAIL MARKET DEVELOPMENTS DURING 2006

2.1 RRO Developments

For residential and eligible small commercial consumers that have not signed a contract with a competitive retailer, the new Regulated Rate Option Regulation (AR 262/2005) ushered in a new process for determination of regulated default rates beginning in July 2006. The new Regulation stipulates a five-year period during which the regulated rate mechanism will transition, to a rate based fully on the forward month energy price via annually escalating the proportion of the month-ahead energy component. The key elements of the rate setting process are defined by individual corporate price setting plans established in accordance with the Regulation. In relation to the majority of RRO eligible customers in the province, these plans were negotiated by parties who represented consumers and the individual RRO providers (Enmax, Epcor, and Direct Energy). At the conclusion of those negotiations, all terms and conditions of the plans were approved by the EUB.

One of the changes to the price setting for RRO is that the monthly price must be available to consumers 5 days before the first day of the delivery month. As well, the monthly price is now calculated by taking a combination of long term hedge prices and the forward price for the month of delivery. To arrive at the long term hedge price, Epcor and Enmax run periodic auctions for full-load RRO requirements which are facilitated by NGX. For the component of the price set by the month of delivery, Epcor and Enmax rely on the prices determined by the bids, offers, and trades which make up the NGX forward month index. The Direct Energy price setting plan has a somewhat different mechanism which does not use either the full-load auctions or the NGX forward month index. The MSA has closely monitored the new RRO process from the outset.

During 2006, Epcor held 16 auction sessions for the procurement of full-load RRO requirement of various contract terms. Enmax held 9 auction sessions also of various contract terms including quarter, half-year, and full-year. The auctions were observed to be well contested and competitive.

Forward energy volumes traded on NGX showed a significant increase following initial stages of the new RRO procurement rollout and have continued to look robust. Forward month volumes have been a significant component of the increased volumes implying that the RRO has added to liquidity in the forward market.

2.2 Retail Market Metrics

For 2006, in terms of overall market share by load, the biggest group are self-retailers (28%) who are typically major industrial companies sufficiently sophisticated to manage their own electricity needs. Of the balance of the load, two major retailers account for 46% of the total, two more each have a 5% share and the balance is divided among many smaller firms. The year over year overall change is quite modest. The shares have seasonality as well as trend components, as is evident on the figure showing quarterly market shares throughout 2006.

The situation regarding who serves which class of customer is somewhat different. At the residential level, four main retailers provide service:

	Enmax	Epcor	Direct	AES[1]
Competitive Contracts	✓	✓	✓	✓
RRO Obligation	✓	✓	✓	

[1] Alberta Energy Savings L.P.

It should be noted that AESP is a pure competitive retailer with no obligation to provide RRO service. The market shares by retailer have not changed dramatically, this despite some significant efforts by retailers to attract customers away from RRO. This is a bit misleading as when a retailer converts a customer to a competitive contract and that customer was already being served by the same retailer as an RRO customer, there is no change in market share for that retailer. For example, a Calgary resident on RRO who switches to an Enmax competitive contract does not change Enmax's market share of RRO eligible load. This effect of the change shows up in the customer switching statistics figures. The data shows that Albertans are gradually making choices in who will provide them electricity and are moving away from the RRO. The Alberta Government is proposing to publish switching statistics on a frequent basis beginning in the near future.

Competition to serve different segments of the retail market is of interest to the MSA. The ebb and flow of market shares observed in each category is taken as a sign of robust competition.

2.3 Code of Conduct Regulation

Compliance Plans

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

Pursuant to the Roles, Relationships and Responsibilities Regulation, 2003 Amendment Regulation, and consistent with other enactments governing retailers, an REA (rural electrification association) is now able to carry out retailer functions for its members without setting up a distinct legal entity separate from the owner entity. By the end of 2006, four REAs had begun to carry out retailer functions for their members (and a fifth commenced offering a non-RRO option January 1, 2007).

As at January 1, 2007, a total of sixteen entities were operating under approved compliance plans.

Code of Conduct Audits 2006

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

As in previous years, the MSA elected to test Code compliance through one independent audit firm retained by the MSA (Grant Thornton LLP), utilizing one common testing plan. The period tested was July 1, 2005 through June 30, 2006.

A total of 13 parties were subject to the testing, including Battle River REA, Central Alberta REA, and entities within the Direct Energy, ENMAX, EPCOR organizations.

Government led discussions about rationalizing the gas and electricity Code regulations, and the possibility that the EUB will take over some electricity Code responsibilities, led the MSA to invite the EUB to participate as an observer in the 2006 Code audit planning. The goal was to facilitate a smooth transition of responsibilities in the event that the EUB does assume some responsibility for the electricity Code (particularly regarding the utilities subject to regulation by the EUB), through acquainting the EUB with the approaches taken by the MSA and by Grant Thornton. Additionally, the planning process benefited from insights garnered from the EUB, as pertained to its own utility audit process. The EUB does not regulate the rural electrification associations (REAs).

Grant Thornton carried out random call centre testing in May and June, 2006, and the balance of the testing plan was carried out between August and October. The MSA posted the results of the testing on its website in December.

The results of the compliance testing were very positive and encouraging overall, showing improvement over the results of the previous audit for the 2004/2005 test period (and those previous results were themselves generally positive).

3 FEATURED ANCILLARY SERVICES MARKET DEVELOPMENTS DURING 2006

3.1 Active Reserves

Average prices of the active reserves exhibited small differences among the three products. The discounts to Pool price also varied over the year, although the general correspondence was quite clear. The volume of procurement by OTC varied appreciably over the year and among the three products. The settlement prices by market (NGX, OTC and combined) indicated no significant concerns in terms of price preference by market.

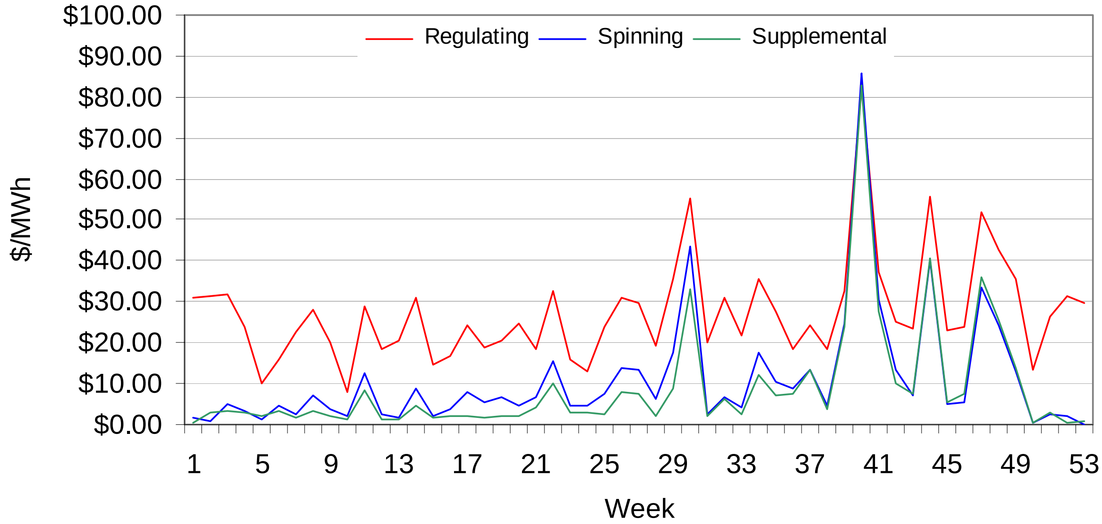
Overall market shares by fuel type continued to show dominance by hydro resources, both local here in Alberta and hydro on the BC Interconnection. Hydro is well suited to providing system reserves due to its energy-limited status. The rather small residual market is then open to the coal, gas and load providers that compete.

3.2 Off-Peak Active Reserve Prices

In its Q1/06 report, the MSA commented on off-peak regulating prices and how expensive they seemed relative to off-peak spinning and off-peak supplementary prices. Further assessment of the data and comparing with the situation that prevailed in Q1/05, it appeared that the change was in fact something of a collapse of prices in off-peak spinning and off-peak supplementary prices. This seemed to have been driven by increased competition in those markets brought on by hydro increasing its market share.

The graph below shows weekly average prices in these markets over the whole of 2006. It can be seen that the circumstances of Q1 appear to have continued on through most of the year. The off-peak pool prices over the second half of 2006 averaged $56/MWh compared with $32/MWh in the first half. The price of natural gas was also substantially lower over the second half of 2006 except for the periods of notable scarcity (late July and early October), the prices of off-peak regulating reserves continued to remain higher than those of off-peak spinning and supplemental reserves. Accordingly, the ability of gas generators to compete in the active reserves markets was much improved, although higher energy prices also meant increased competition in the reserves markets. The average prices for off-peak regulating reserve trended up over the second half of the year but not as rapidly as the recovery of off-peak spinning and off-peak supplementary reserve prices.

2006 Weekly Average Off Peak Clearing Prices (by week)



3.3 Standby Reserves

The premium paid to providers of standby reserves varied through the year, although at any given time, the spread across products (regulating, spinning, and supplemental) was modest. Activation prices also varied through the year with noticeably high values in October when competition for supply was severe.

4 OTHER MSA ACTIVITIES

4.1 MSA Consultation Process

In 2006, the MSA committed to working with stakeholders to develop a defined basis for stakeholder involvement in future market initiatives – for example, development of MSA Guidelines. In early May 2006, the MSA began discussions with stakeholders to define the framework of the new process. After considering stakeholder feedback, the MSA issued its final report in late July entitled “Principles for Stakeholder Engagement, and a Common Framework, for MSA Public Projects”. As yet, the new engagement process has not been put into use. Following the completion of the first two projects that use the process, the MSA has committed to undertaking an evaluation of how well it is functioning.

4.2 TPG Investigation

The MSA identified a breach of the Trading Practices Guideline (TPG) by the conduct of Enmax Energy Corporation and Enmax Energy Marketing Inc. on November 8, 2005. After completing its investigation into the matter, the MSA chose to pursue a negotiated settlement rather than to bring the matter before a tribunal. Sanctions included: a public notice acknowledging the event; submission of a compliance plan with respect to the TPG; and two reviews of compliance and related procedures. The MSA is satisfied that these negotiated sanctions were appropriate to the transgression. Further details regarding the negotiated settlement can be found on the MSA web site.

APPENDIX A – WHOLESALE ENERGY MARKET METRICS

Table 1 - Pool Price Statistics

2006	Average Price	On-Pk Price	Off-Pk Price	Std Dev[1]	Coeff. Variation[2]
Jan - 06	72.12	93.21	47.60	58.57	81%
Feb - 06	54.07	65.56	38.76	30.35	56%
Mar - 06	44.08	51.54	33.74	27.68	63%
Apr - 06	42.87	56.02	26.37	46.59	109%
May - 06	56.26	76.55	30.52	77.70	138%
Jun - 06	61.64	86.28	27.92	96.09	156%
Jul - 06	128.23	167.78	82.24	199.59	156%
Aug - 06	73.46	92.83	46.65	99.46	135%
Sep - 06	82.53	112.07	45.61	126.44	153%
Oct - 06	174.09	235.51	96.43	200.63	115%
Nov - 06	105.47	132.45	71.75	131.28	124%
Dec - 06	70.88	90.13	48.49	87.61	124%
2006	80.79	104.99	49.67	119.41	148%
2005	70.36	86.86	49.28	82.39	117%

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

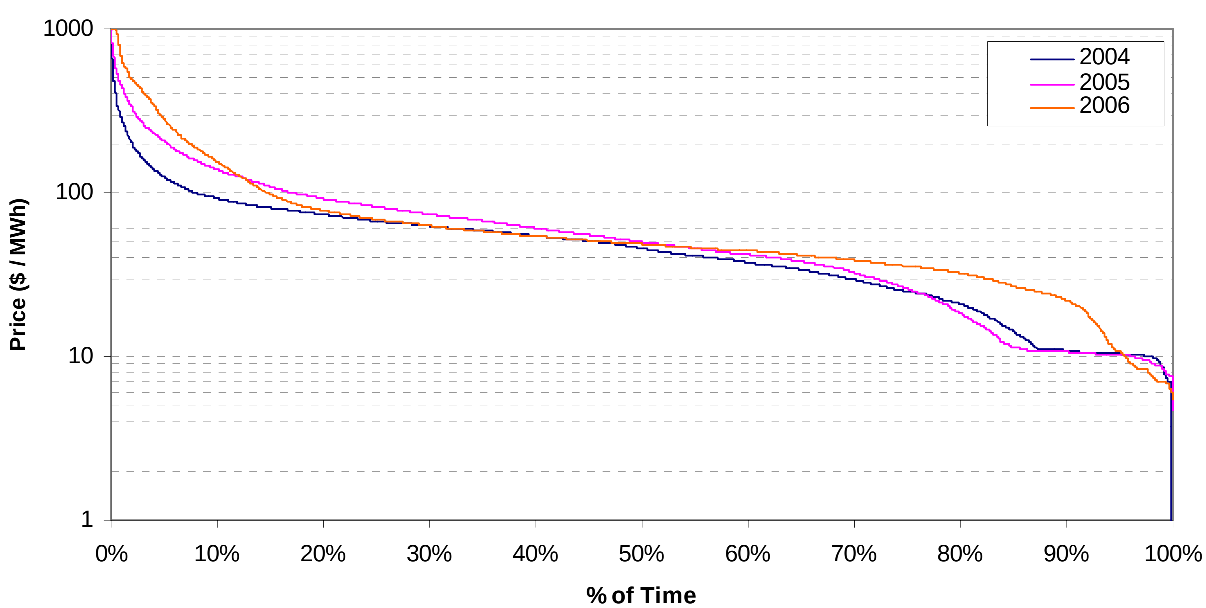


Figure 2 – Pool Price with Pool Price Volatility

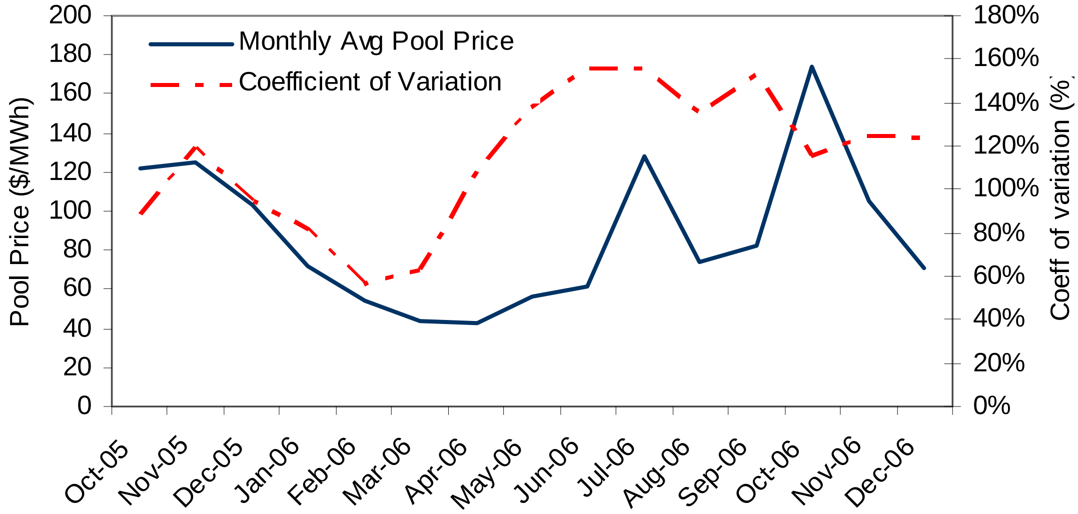


Figure 3 - Wholesale Electricity Price with AECO Gas Price

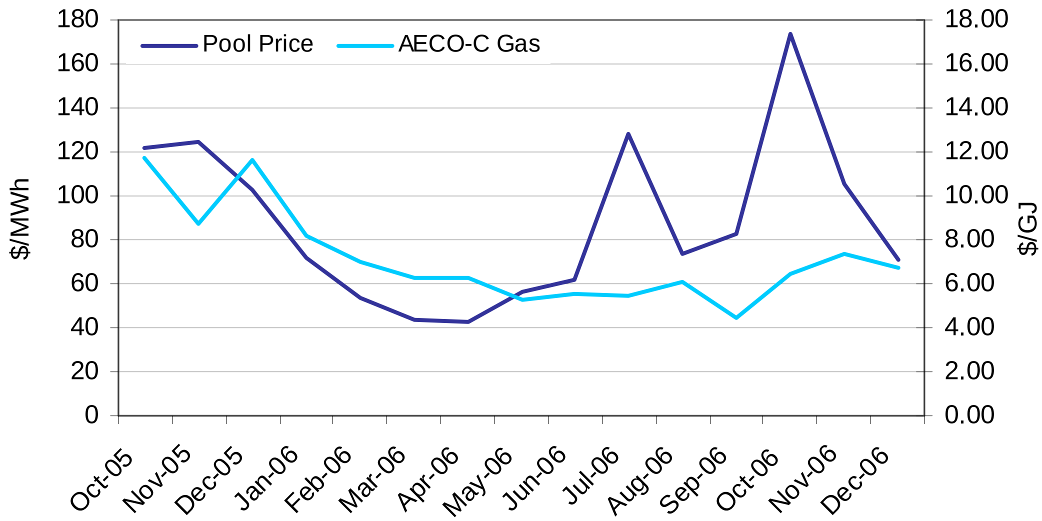


Figure 4 - Price Setters by Participant (All Hours)

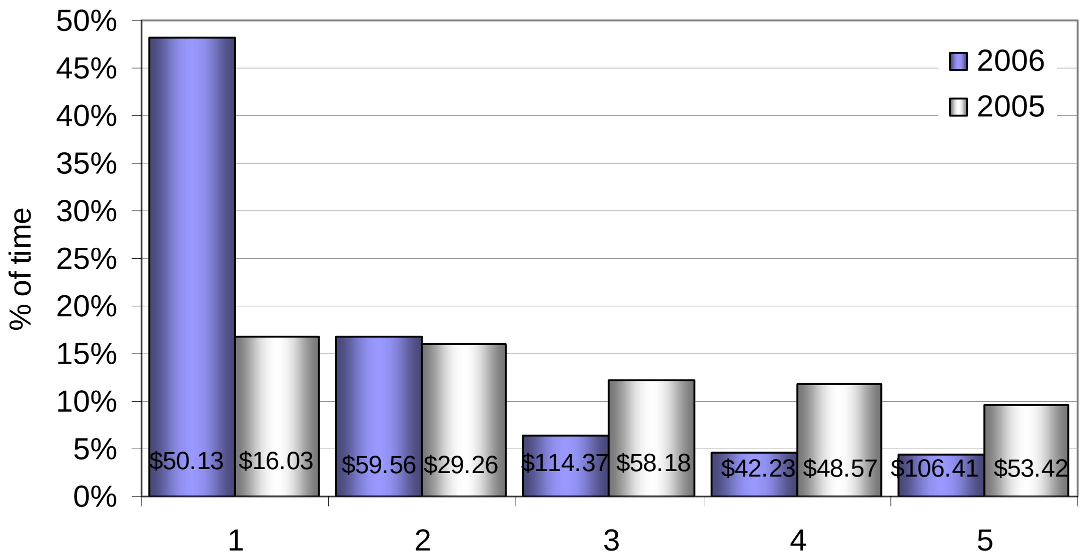


Figure 5 - Price Setters by Fuel Type (All Hours)

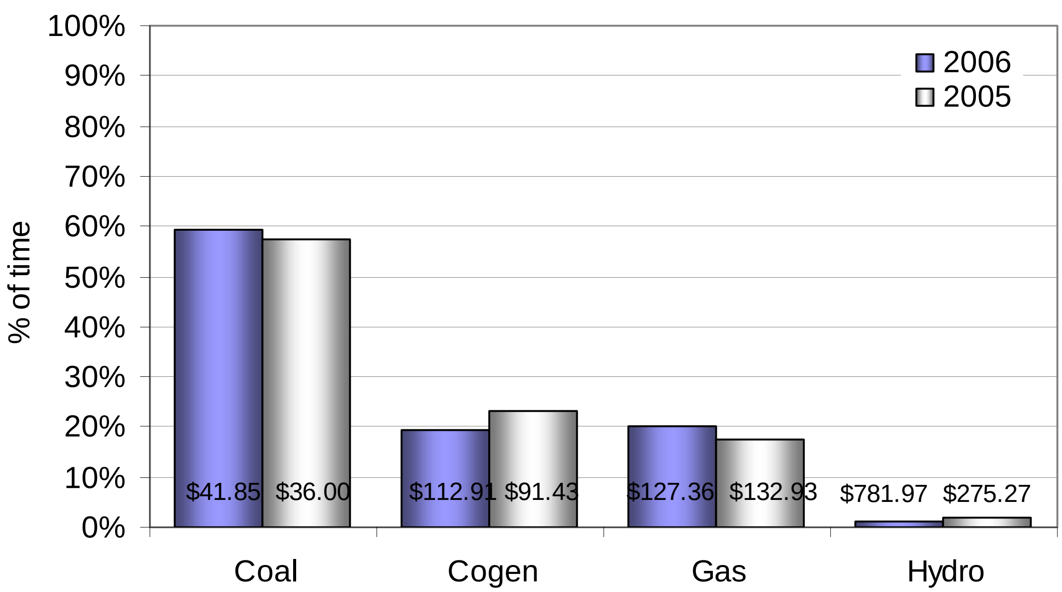


Figure 6 – Heat Rate Duration Curves (All Hours)

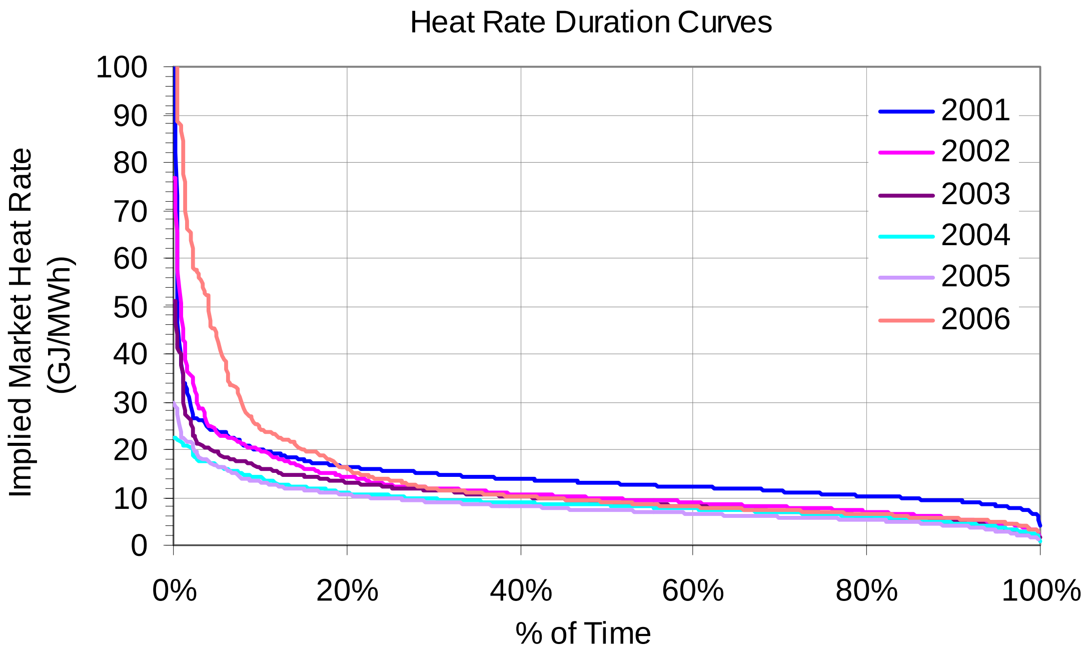


Figure 7 - Implied Market Heat Rates (2006)

Month	On-Peak	Off-Peak	All Hours
January	11.5	5.0	8.9
February	9.4	4.9	7.8
March	8.2	5.9	7.0
April	8.9	4.1	6.8
May	14.5	5.1	10.7
June	15.5	4.9	11.2
July	30.0	11.6	23.2
August	15.4	7.1	12.2
September	24.9	10.0	18.4
October	48.9	18.4	36.3
November	18.0	8.6	14.3
December	13.0	6.5	10.3
Average	18.2	7.7	13.9

Figure 8 – Zero Offers

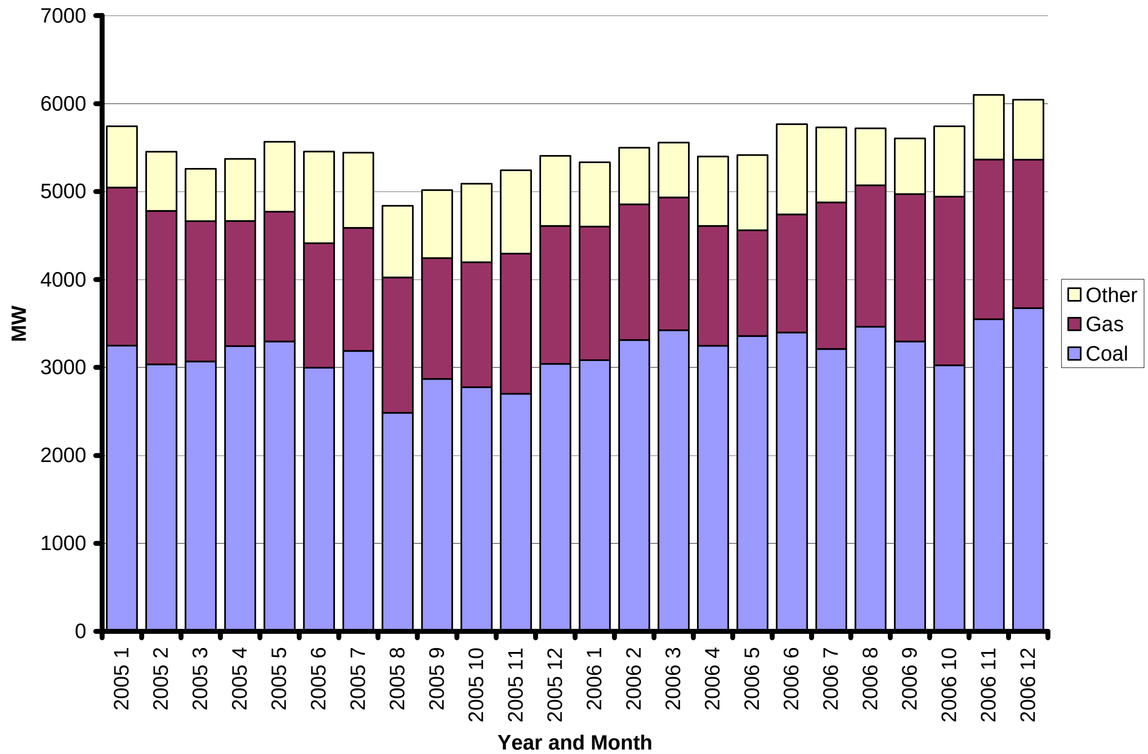


Figure 9 – PPA Total Outages by Quarter

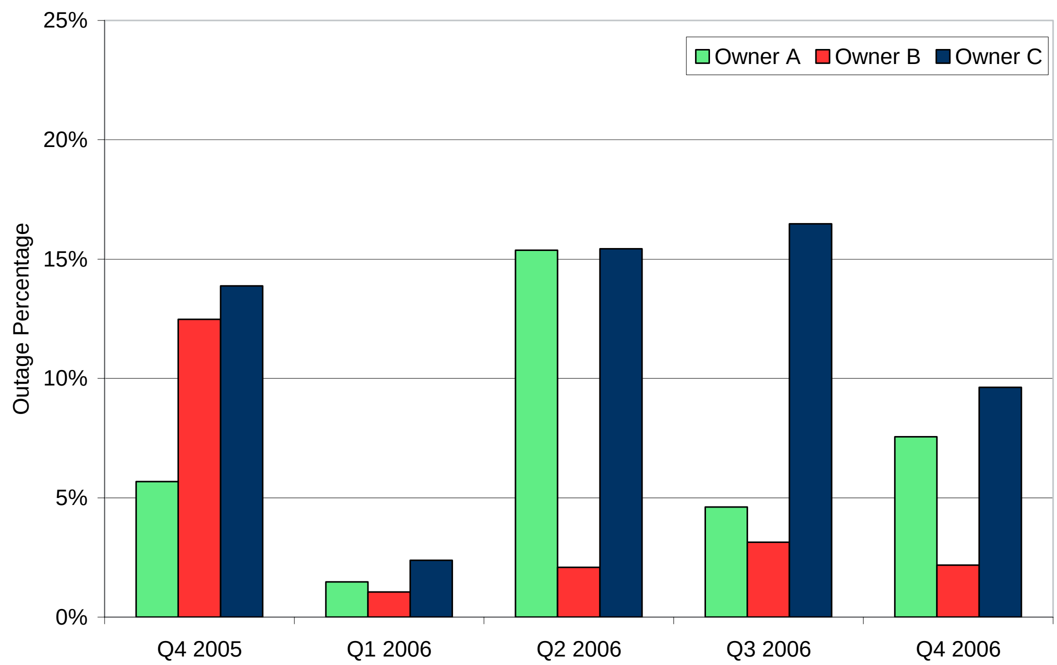


Table 2 – Percentage of Unplanned Outages for PPA Units

	Q4/06	Q3/06	Q2/06	Q1/06	2006	2005	2004	2003	2002
Owner-A	**7.1%**	3.1%	9.3%	1.4%	**5.2%**	5.0%	6.1%	4.9%	4.2%
Owner-B	**2.1%**	2.4%	1.8%	1.0%	**1.8%**	5.4%	1.5%	1.5%	0.5%
Owner-C	**6.5%**	7.9%	4.9%	1.9%	**5.3%**	6.5%	6.3%	5.7%	10.8%
PPA weighted average	**6.0%**	5.7%	5.7%	1.6%	**4.8%**	5.9%	5.5%	4.9%	7.7%

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

Table 3 – MW Weighted Portfolio Target Availability (%) vs Actual Availability (%) – Coal Fired PPA Units

	Target Availability 2004	Actual Availability 2004	Target Availability 2005	Actual Availability 2005	Target Availability 2006	Actual Availability 2006
Owner-A	87%	88%	87%	90%	87%	93%
Owner-B	90%	97%	89%	90%	89%	98%
Owner-C	87%	89%	87%	88%	87%	89%
PPA weighted Average	87%	90%	87%	89%	87%	91%

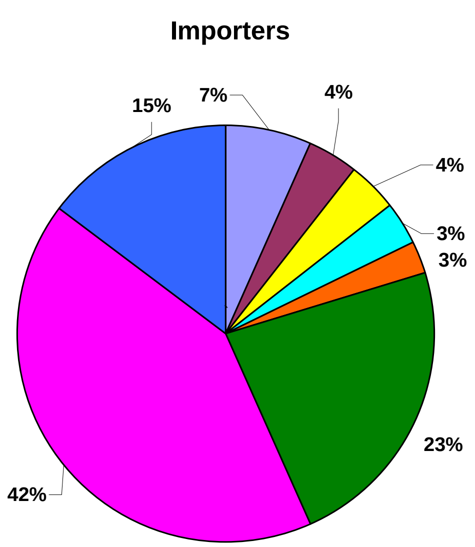
APPENDIX B – TIE LINE METRICS

Table 4 – 2006 Tie Line Statistics

	BC			Saskatchewan			Overall		
	Imports (MWh)	Exports (MWh)	Net Imports (MWh)	Imports (MWh)	Exports (MWh)	Net Imports (MWh)	Imports (MWh)	Exports (MWh)	Net Imports (MWh)
January	47,228	23,123	24,105	50,630	610	50,020	97,858	23,733	74,125
February	26,131	15,277	10,854	15,736	1,792	13,944	41,867	17,069	24,798
March	14,676	25,757	-11,081	19,172	4,289	14,883	33,848	30,046	3,802
Q1 Total	88,035	64,157	23,878	85,538	6,691	78,847	173,573	70,848	102,725
April	122,482	6,670	115,812	42,461	3,596	38,865	164,943	10,266	154,677
May	150,136	1,927	148,209	40,739	2,657	38,082	190,875	4,584	186,291
June	216,623	3,290	213,333	61,366	1,104	60,262	277,989	4,394	273,595
Q2 Total	489,241	11,887	477,354	144,566	7,357	137,209	633,807	19,244	614,563
July	130,444	22,770	107,674	48,666	2,495	46,171	179,110	25,265	153,845
August	51,012	78,267	-27,255	21,350	2,677	18,673	72,362	80,944	-8,582
September	38,551	83,451	-44,900	31,105	571	30,534	69,656	84,022	-14,366
Q3 Total	220,007	184,488	35,519	101,121	5,743	95,378	321,128	190,231	130,897
October	156,987	30,547	126,440	26,556	2,819	23,737	183,543	33,366	150,177
November	103,894	41,900	61,994	18,728	2,964	15,764	122,622	44,864	77,758
December	43,043	127,071	-84,028	39,319	3,841	35,478	82,362	130,912	-48,550
Q4 Total	303,924	199,518	104,406	84,603	9,624	74,979	388,527	209,142	179,385
2006 Total	**1,101,207**	**460,050**	**641,157**	**415,828**	**29,415**	**386,413**	**1,517,035**	**489,465**	**1,027,570**

Note: Import and Export figures shown above are relative to Alberta ie: BC imports means import volumes flowing to Alberta from BC

Figure 10 – Market Share of Importers and Exporters (2006)



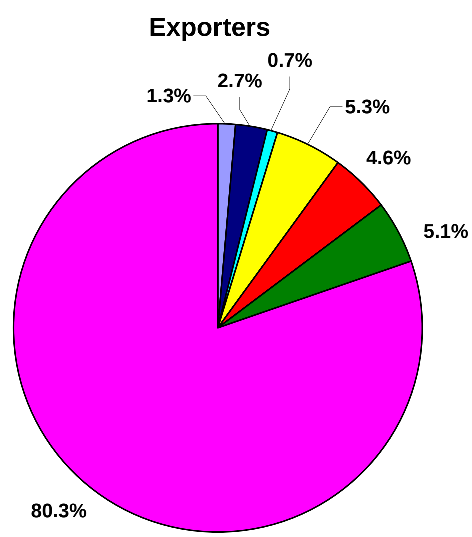


Figure 11 - Tie Line Utilization (2006)

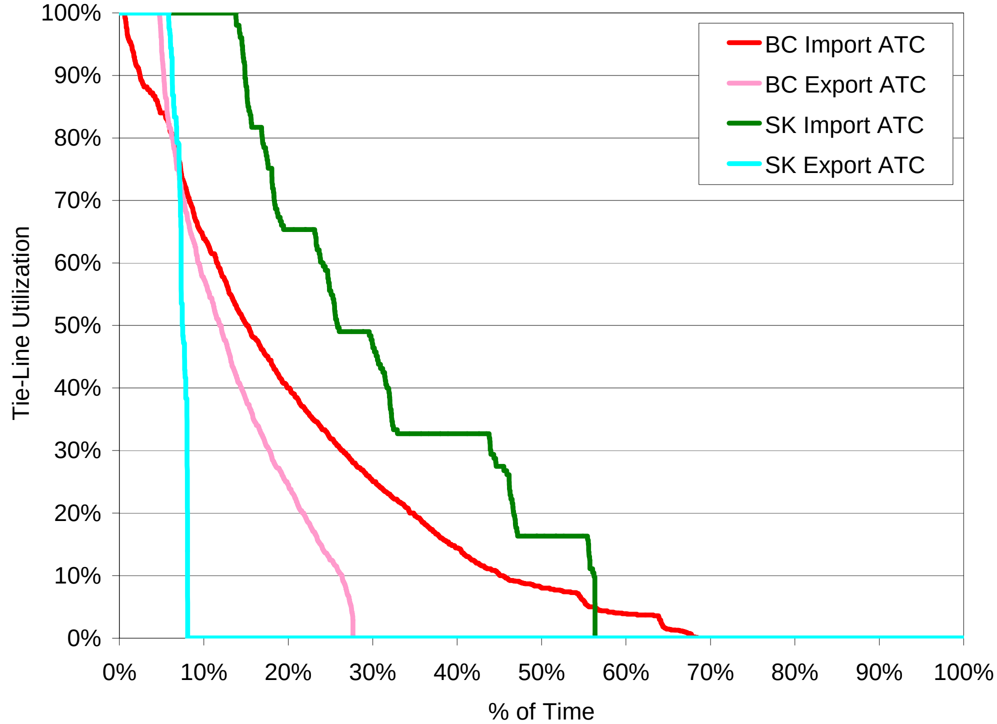


Figure 12 - Imports with Trade-weighted Prices

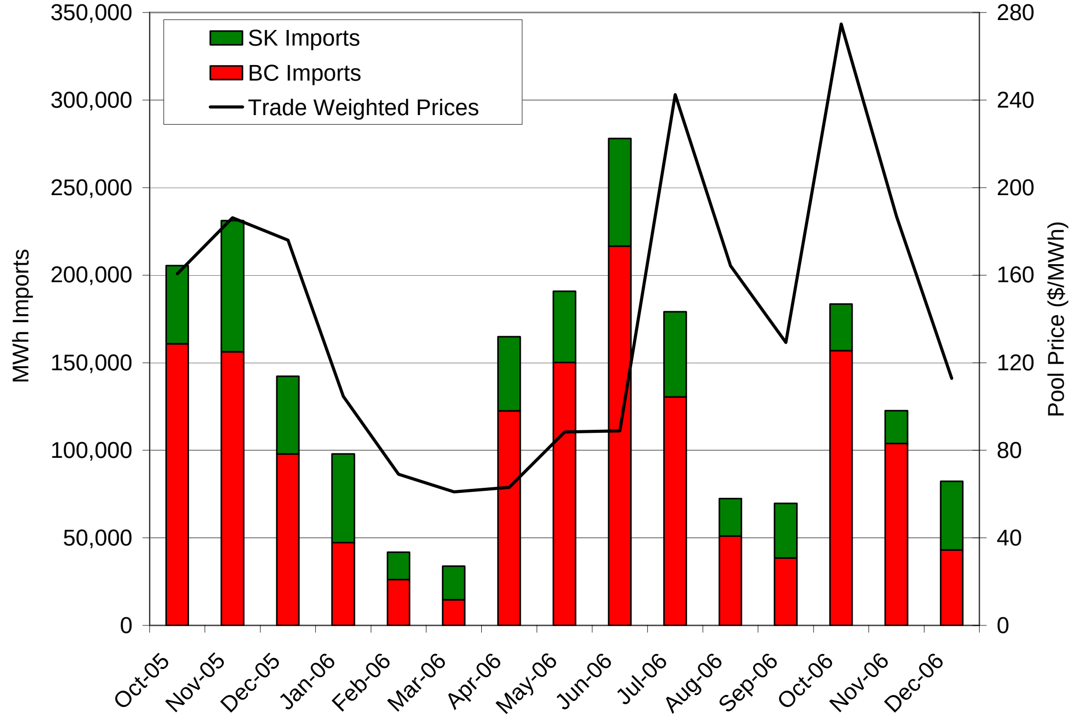


Figure 13 - Exports with Trade-weighted Prices

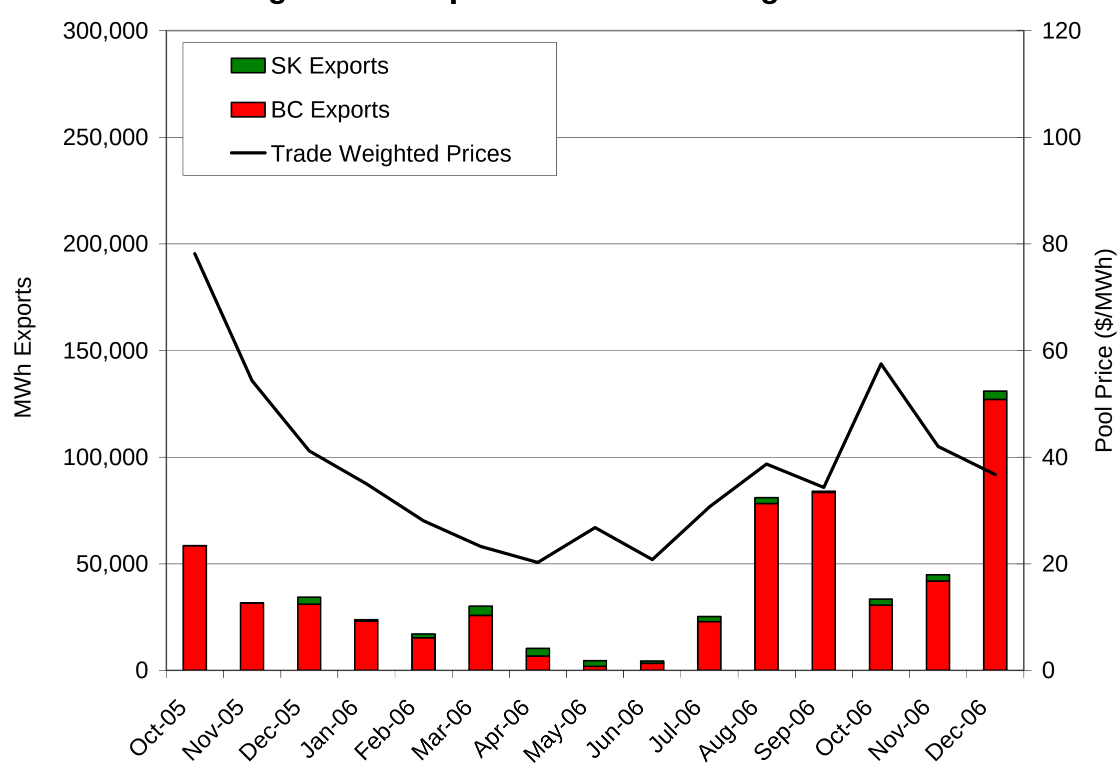


Figure 14 - On-Peak Prices in Other Markets

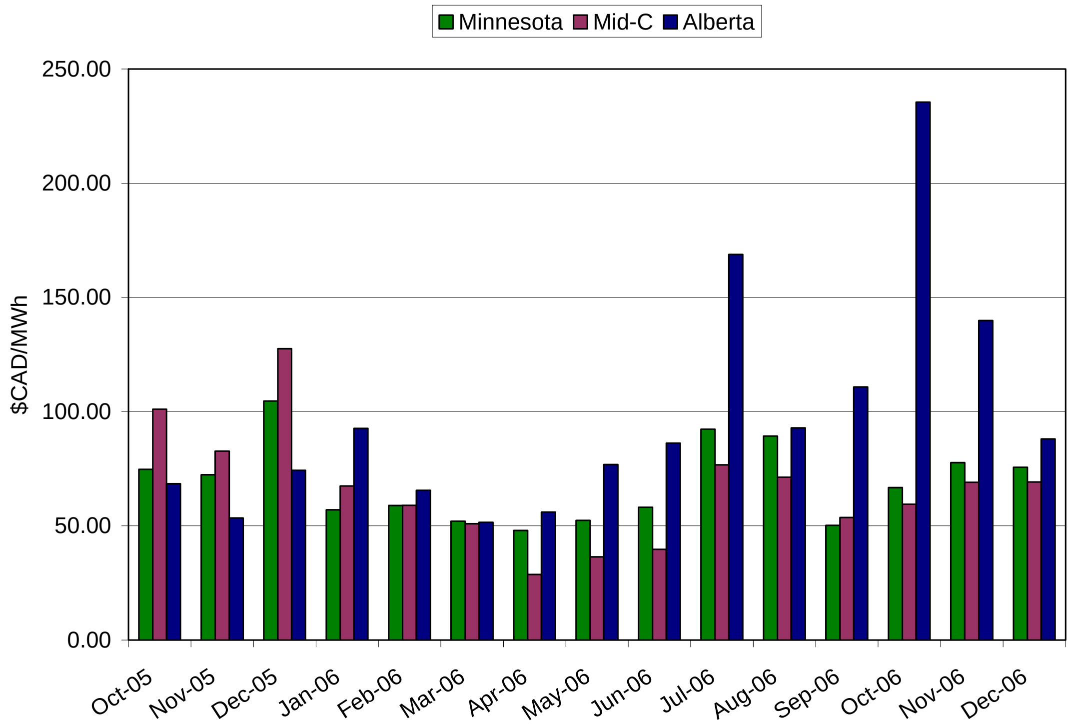
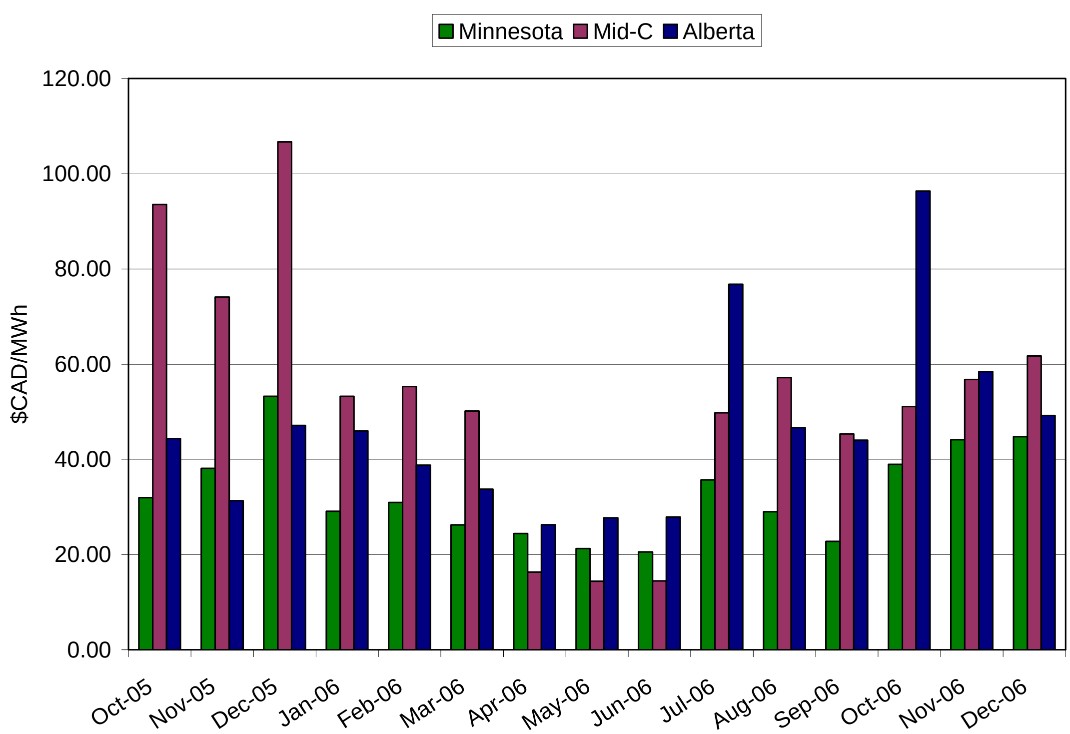


Figure 15 - Off-Peak Prices in Other Markets



APPENDIX C – ANCILLARY SERVICES MARKET METRICS

Ancillary services are the system support services that ensure system stability and reliability. The Alberta Interconnected Electric System (AIES) is required to carry sufficient reserves in order to assist in the recovery of any unexpected loss of generation or an interconnection. Reserves are competitively procured by the AESO through the Alberta Watt-Exchange (Watt-Ex) and over the counter (OTC). Standard ancillary services products (contracts) include active and standby products for each of Regulating, Spinning, and Supplemental reserves. The majority of active reserve products are indexed and settled against Pool price prevailing during the contract period. Standby reserve products are priced in a similar manner to options with a fixed premium and an exercise price (activation price). The activation price is only paid in the event that the contract is activated.

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

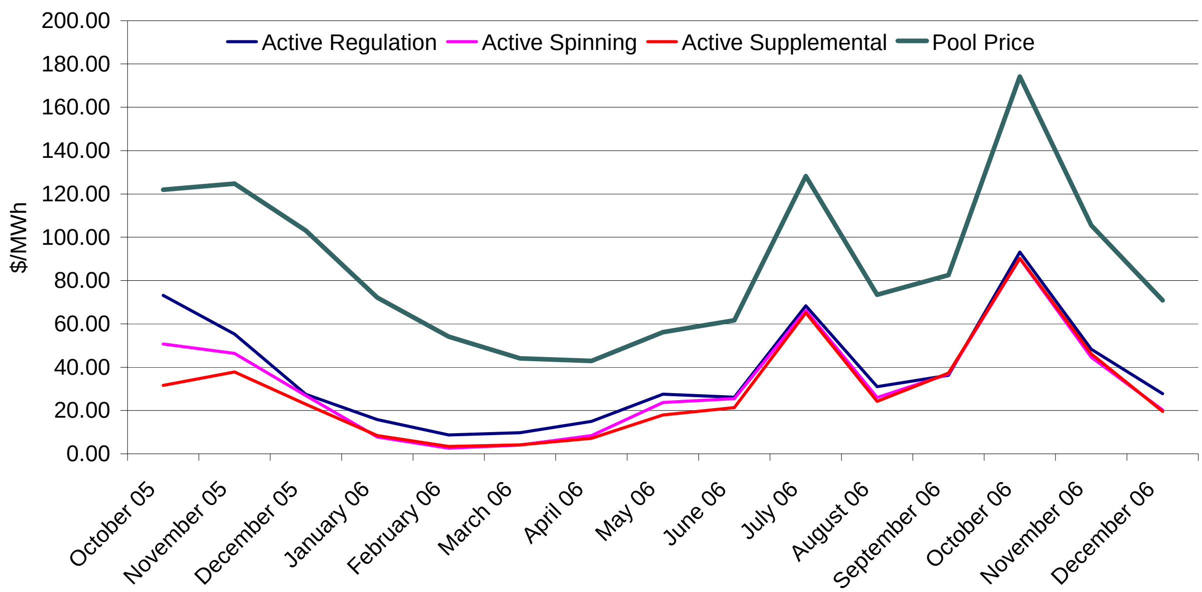


Figure 17 - Standby Premiums - All Markets (Watt-ex and OTC)

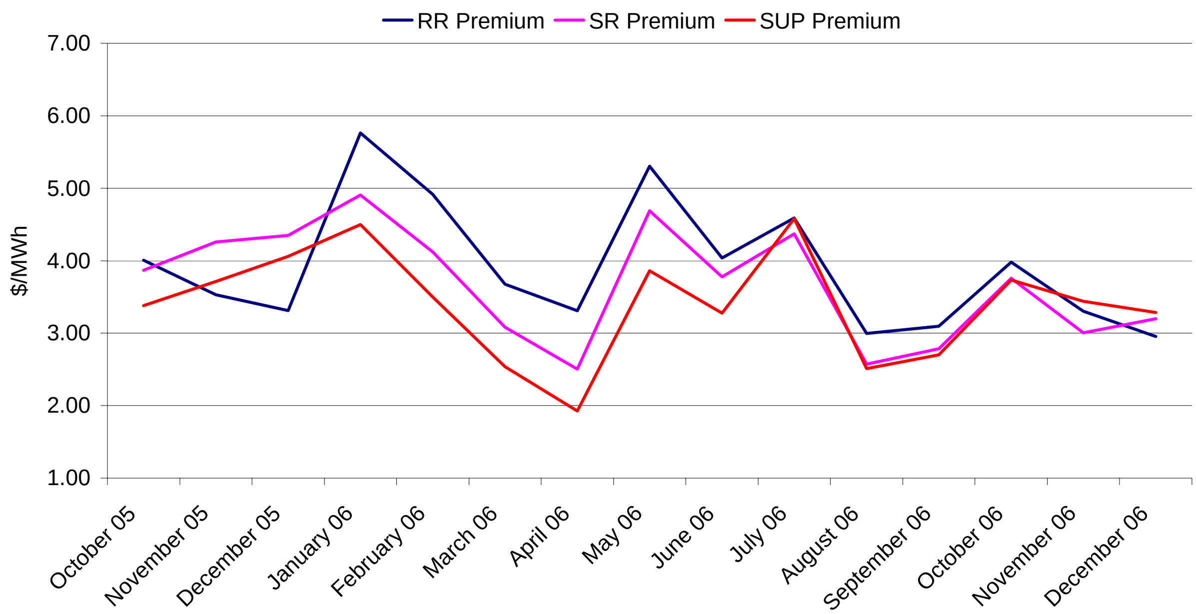


Figure 18 – Activation Prices – All Markets (Watt-ex and OTC)

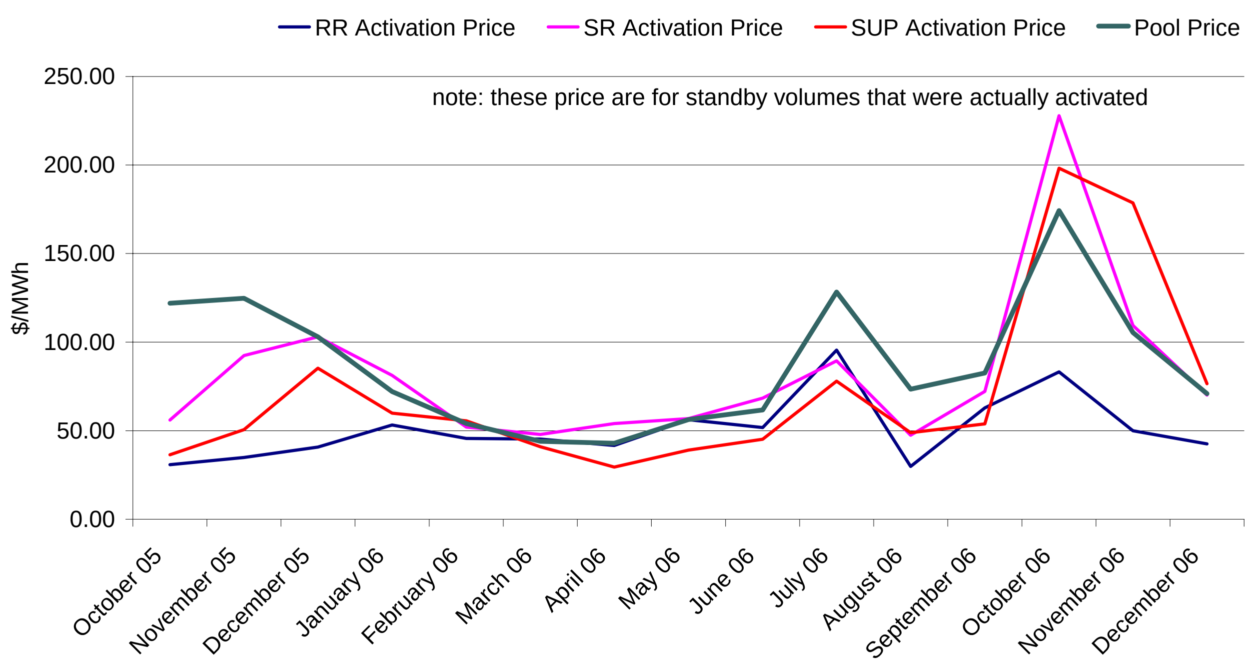


Figure 19 - Standby Activation Rates

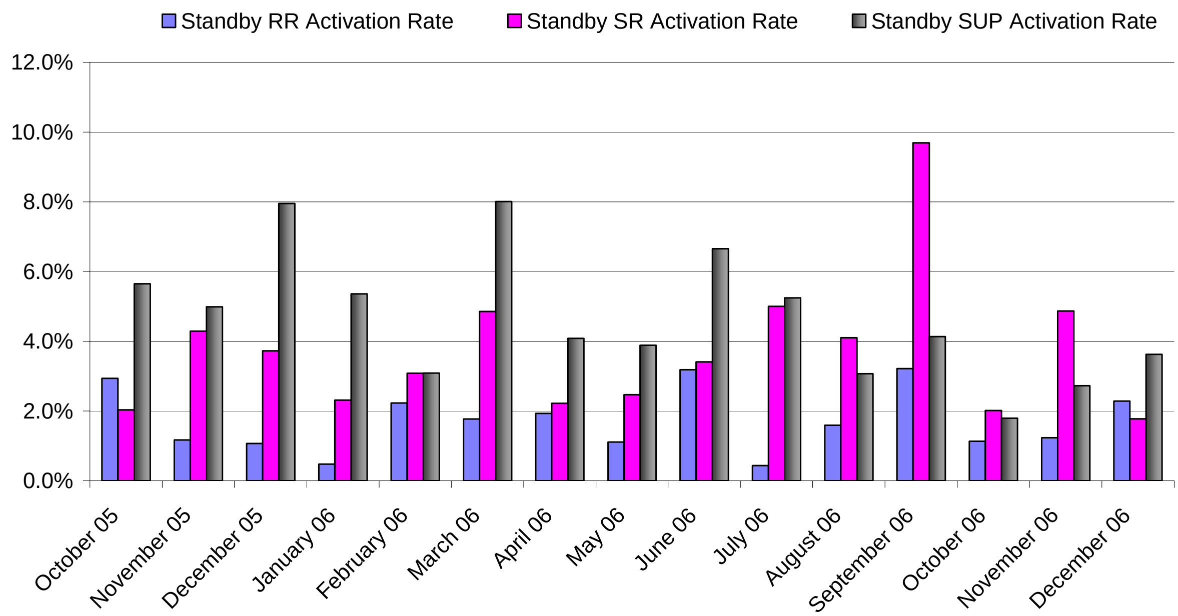


Figure 20 - OTC Procurement as a % of Total Procurement

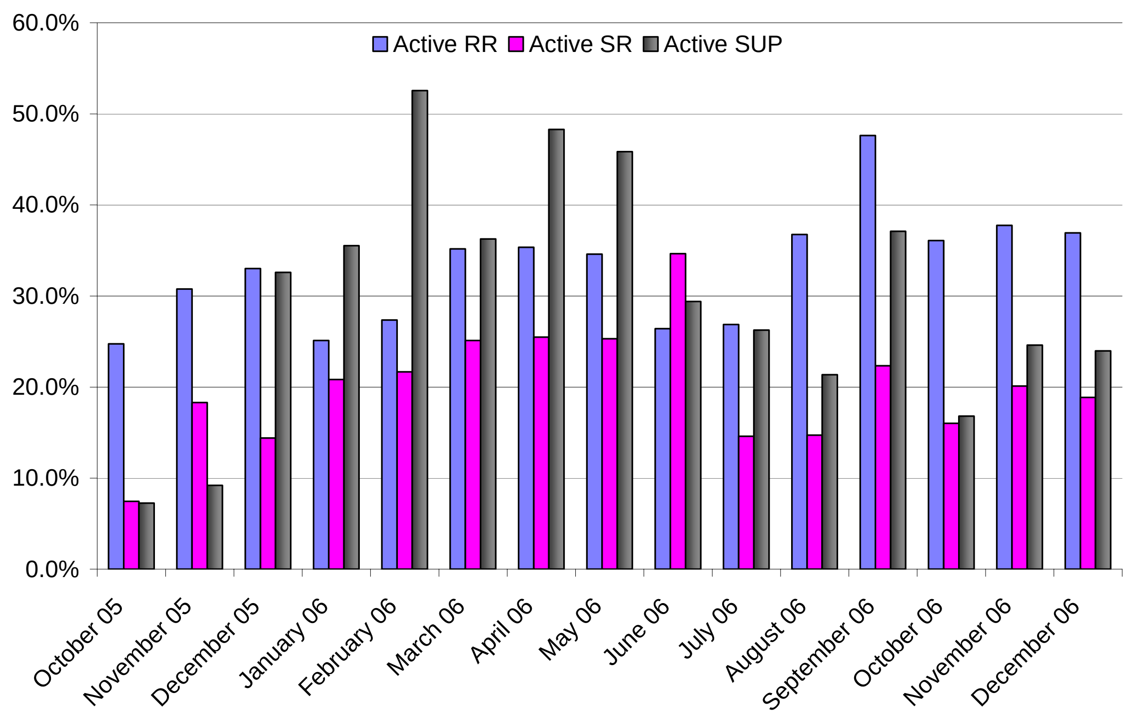


Figure 21 - Active Regulating Reserve Settlement by Market

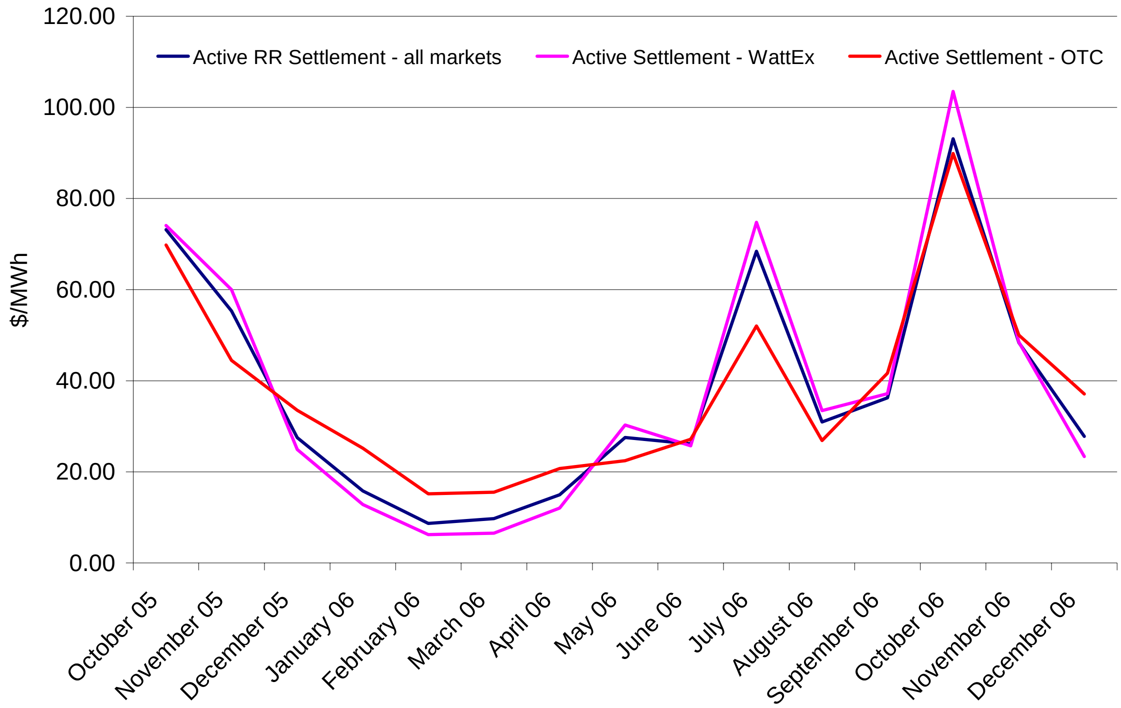


Figure 22 - Active Spinning Reserve Settlement Price by Market

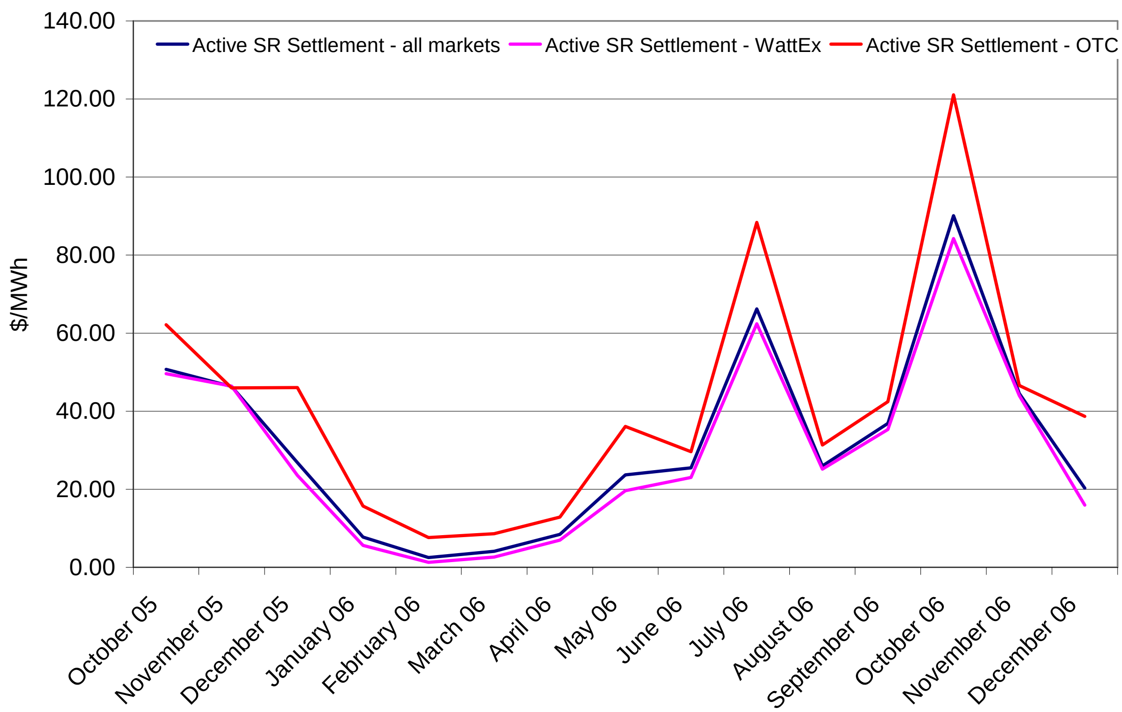


Figure 23 - Active Supplemental Reserve Settlement Price by Market

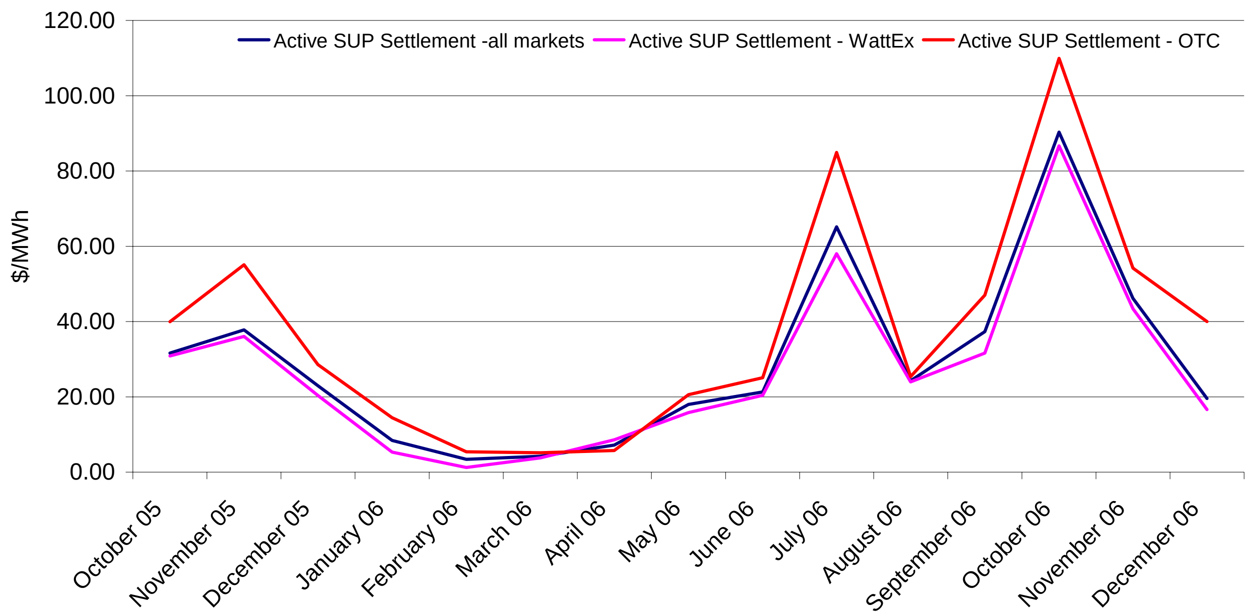


Figure 24 – Active Regulating Reserve Market Share by Fuel Type

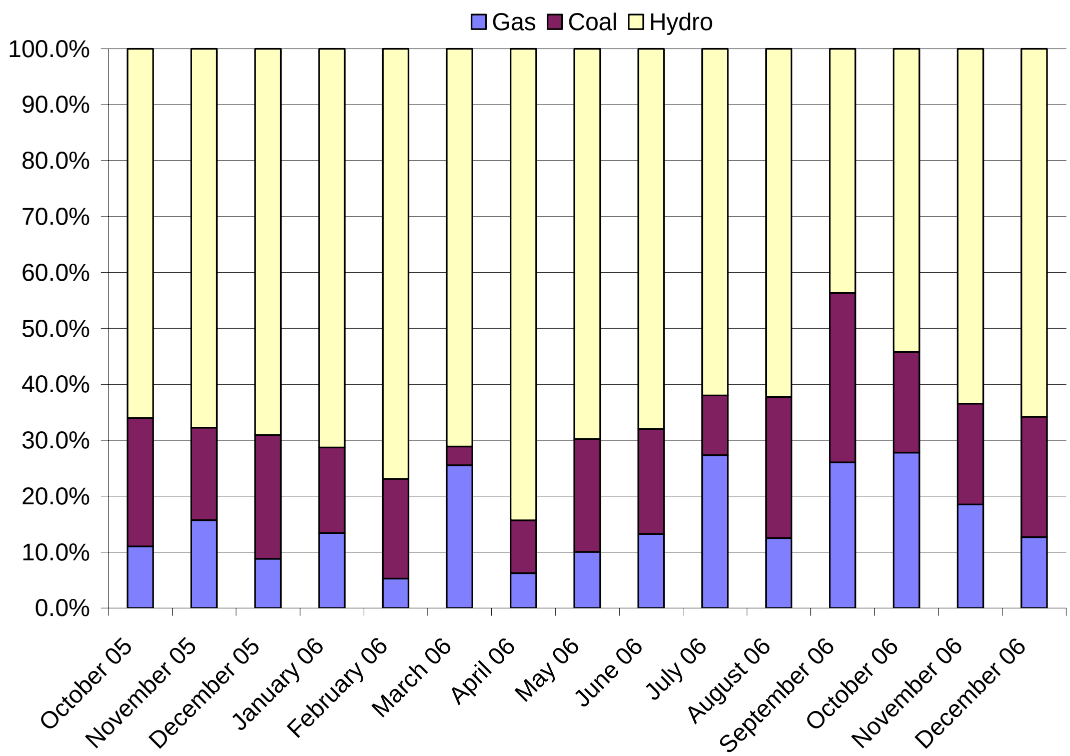


Figure 25 – Active Spinning Reserve Market Share by Fuel Type

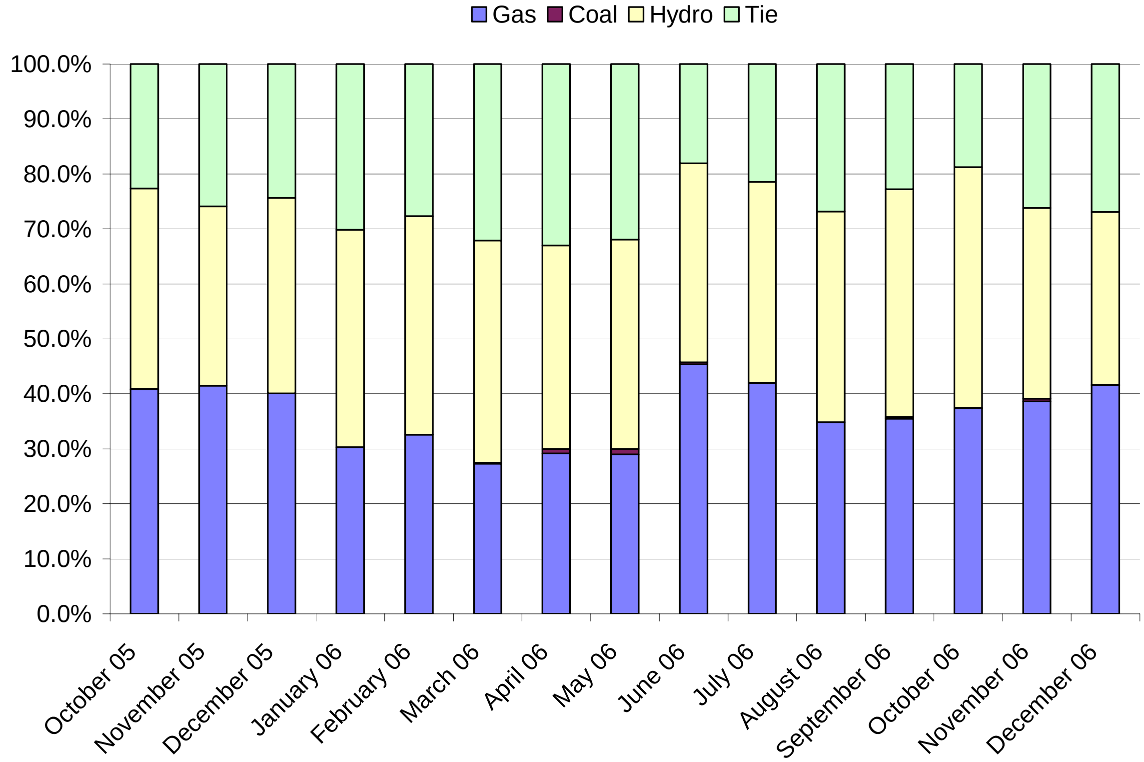
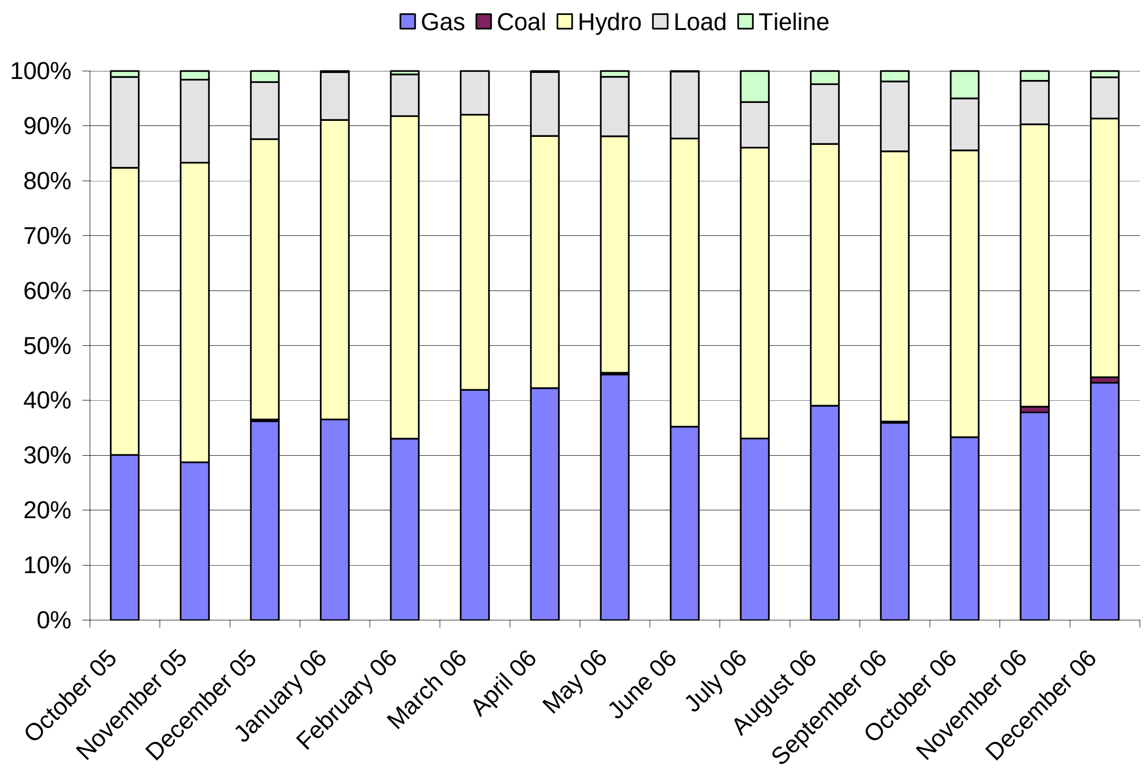


Figure 26 – Active Supplemental Reserve by Fuel Type



APPENDIX D – RETAIL MARKET METRICS

Figure 27 – Current Market Share of Retailers by Load (Q4/06)

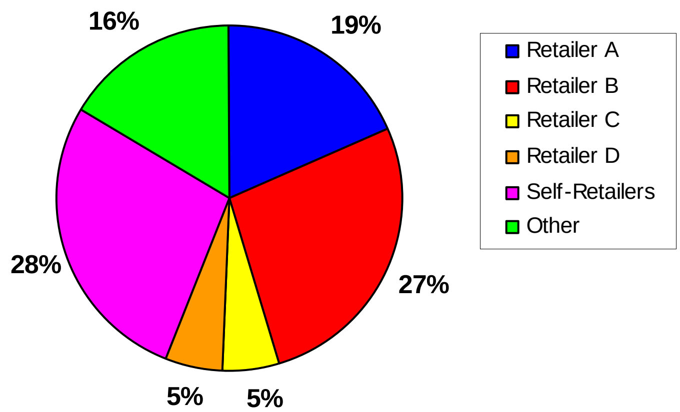
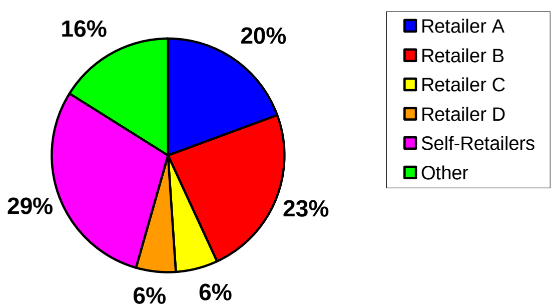
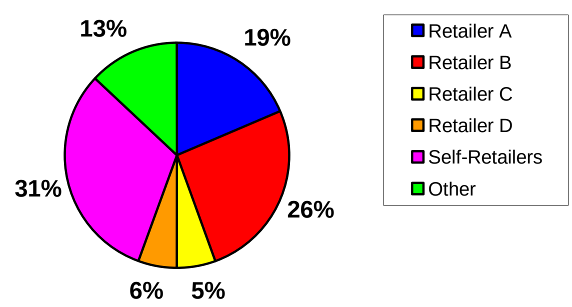


Figure 28 – Historical Market Share of Retailers by Load

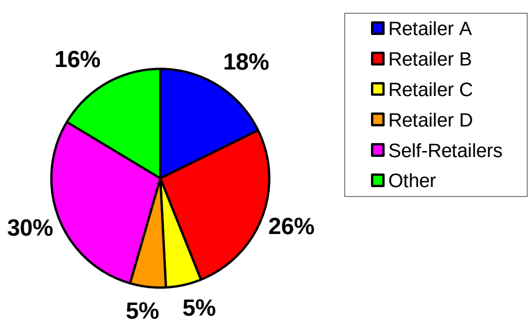
Q1/06



Q2/06



Q3/06



Q4/06

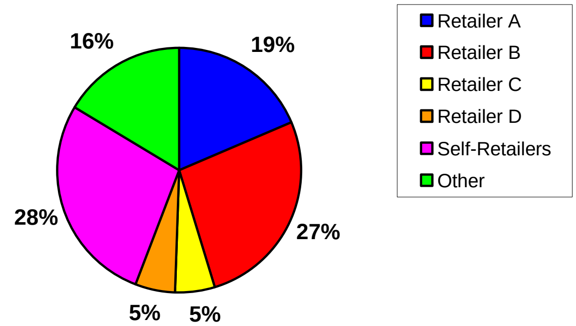


Figure 29 – Market Share of Retailers by Customer Class

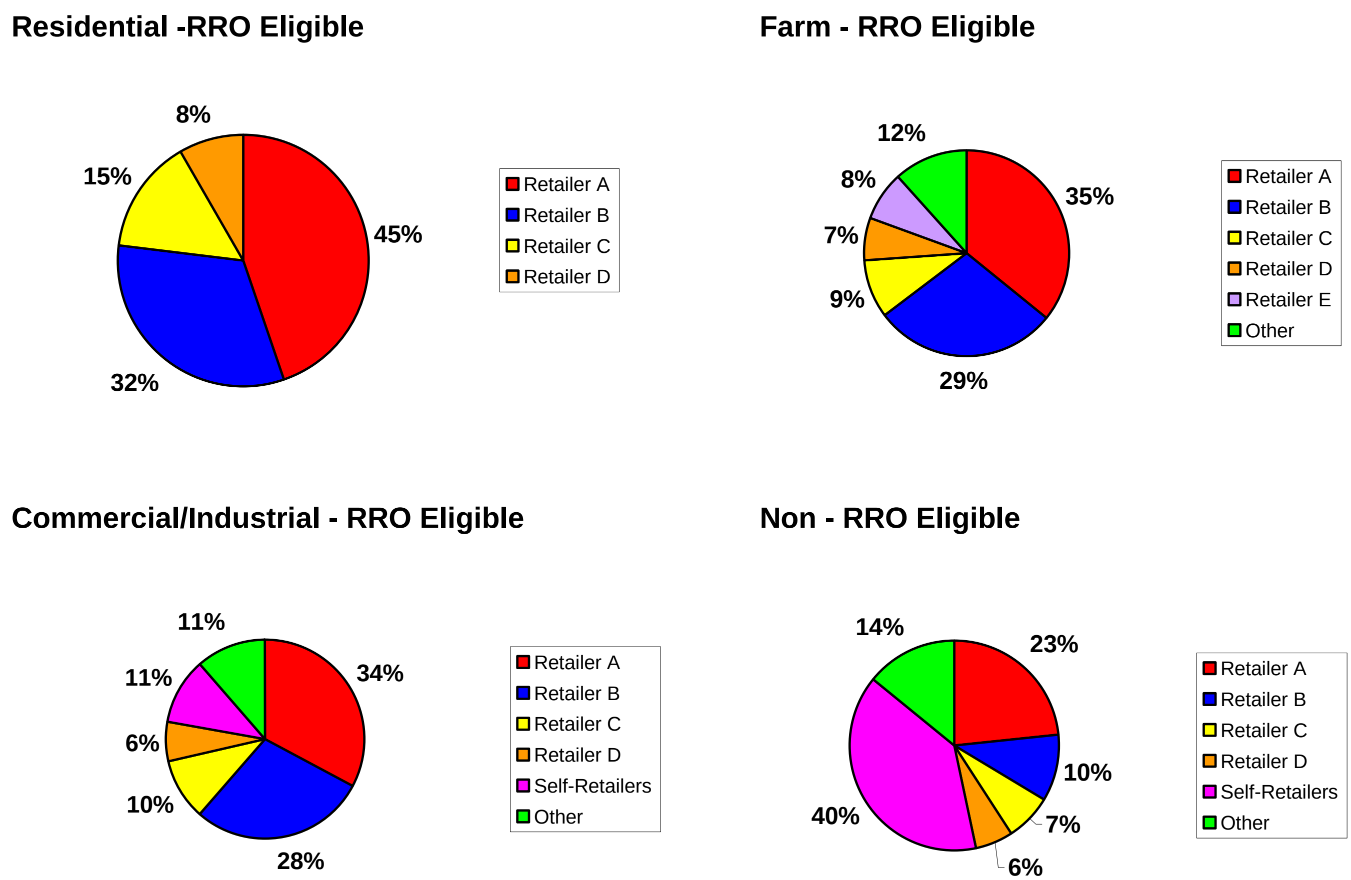
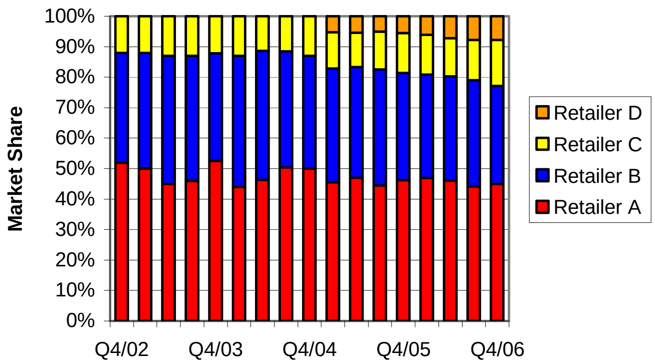
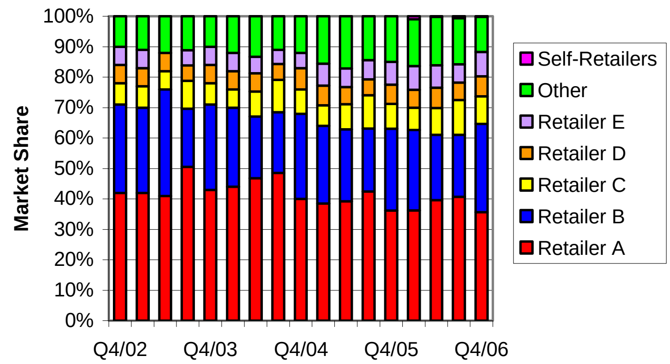


Figure 30 – Change in Market Share by Category

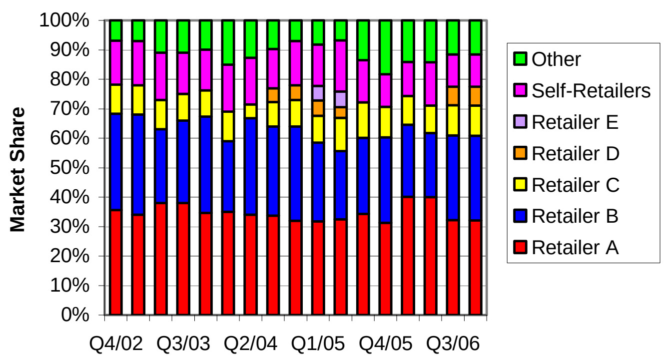
Residential -RRO Eligible



Farm - RRO Eligible



Commercial/Industrial - RRO Eligible



Non - RRO Eligible

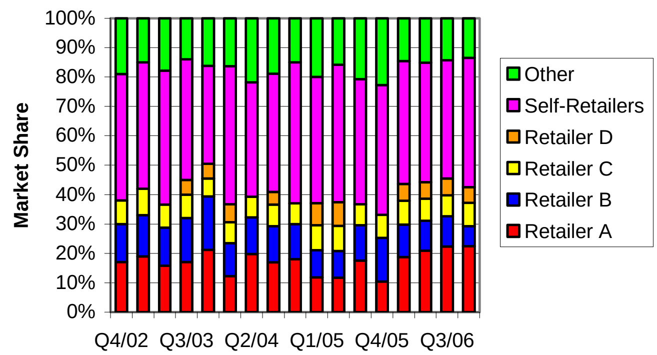


Figure 31 – Progression of Eligible Sites Switching off RRO

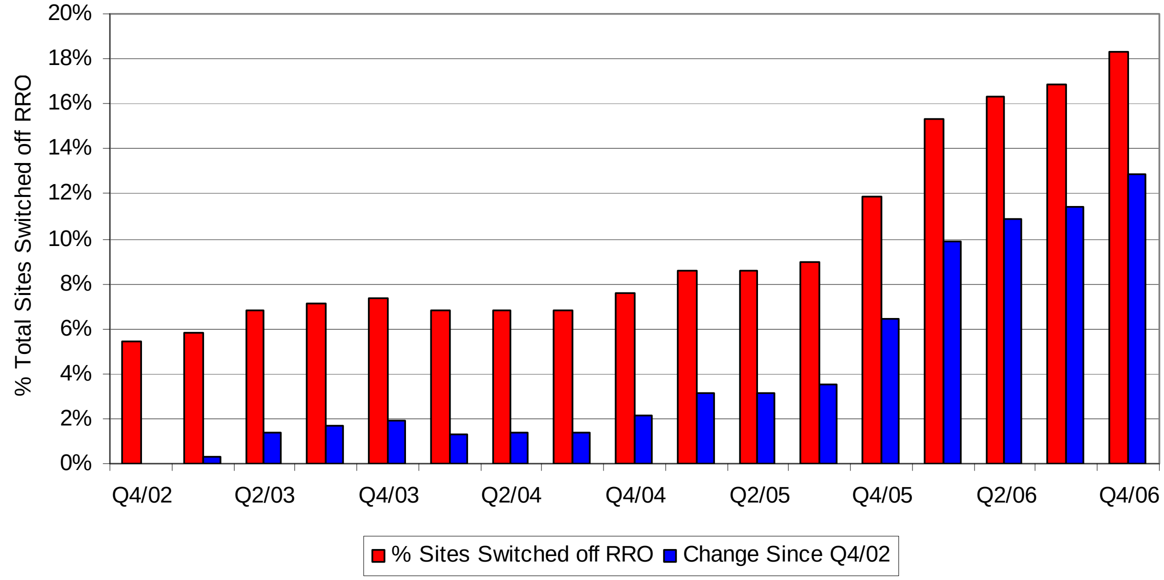
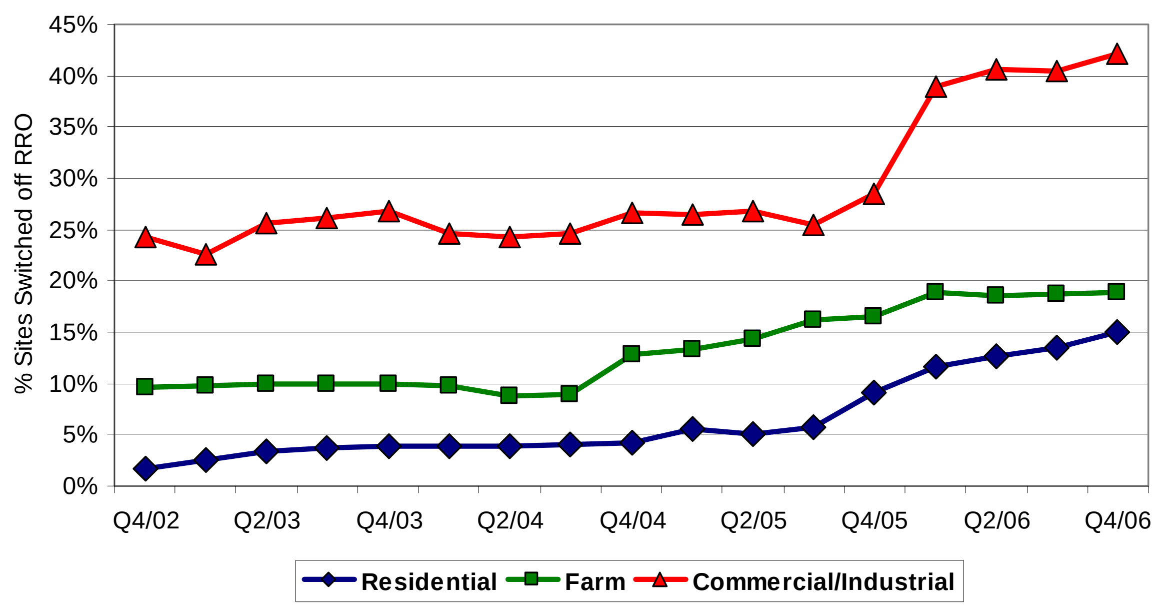


Figure 32 – Progression of Eligible Sites Switching off RRO by Customer Type



PFEC and PFAM, are mechanisms by which corrections and adjustments can be made to settlement calculations pursuant to the retail Settlement System Code ("Code"), which is part of the ISO rules. PFEC ("pre-final error correction"), serves to correct errors prior to a subsequent run of settlement and thus improves settlement results prior to final settlement. PFAM ("Post-final adjustment mechanism"), is a process that market participants must follow when final settlement data is being disputed and the market participants are requesting financial adjustments be made as a result of the dispute.

UFE ("Unaccounted-for energy") reflects the extent of the settlement differences between energy going into the system vs. energy taken out by consumption and losses. UFE reasonable exception reports note instances where UFE was outside the tolerances allowed for in the Code. Load settlement agents (LSAs) are required to investigate and report to the market on such variances.

Table 5 – PFEC Tracking (by Quarter)

Claim Type	Carry-Over	Submitted	Accepted	Rejected	Unresolved
PFEC					
Q4/06	18	396	344	52	18
Q3/06	76	385	396	47	18
Q2/06	76	385	396	47	18
Q1/06	127	641	607	85	76

Table 6 – PFAM Tracking (by Quarter)

Claim Type	Carry-Over	Submitted	Accepted	Rejected	Unresolved	Net kWh Adjustment
PFAM						
Q4/06	10	108	72	36	10	(319,236)
Q3/06	12	103	92	13	10	241,329
Q2/06	21	79	62	28	12	(252,833)
Q1/06	8	149	99	37	21	15,461,264

Table 7 – Summary of UFE Reasonable Exception Reports

Quarter	Outstanding	New	Resolved	Unresolved
Q4/06	267	85	0	352
Q3/06	208	71	12	267
Q2/06	170	39	1	208
Q1/06	132	38	0	170