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MSA Report

Quarterly Report

January – March 2007

27 April, 2007

Market Surveillance Administrator

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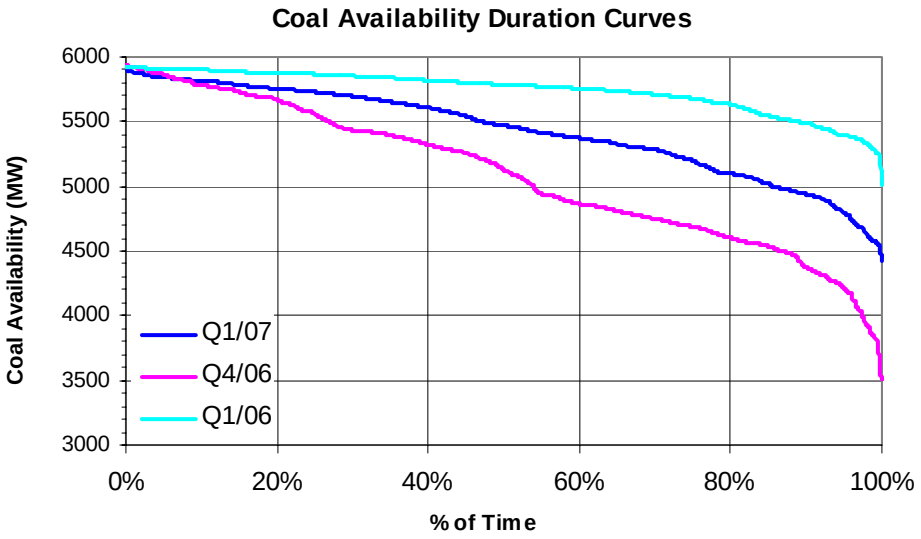
1 FEATURED MARKET DEVELOPMENTS DURING Q1/07

1.1 Wholesale Market Prices

Q1/07 bore a very close resemblance to Q1/06 – both relatively soft priced first quarters following volatile and high priced fourth quarters. In Q1/06, average pool prices were 56.84/MWh following Q4/05 which averaged $116.53/MWh. One year later, Q1/07 wholesale prices averaged $63.29/MWh following Q4/06 which averaged $116.96/MWh. Alberta natural gas prices were also similar, averaging $7.01/GJ in Q1/07 as compared to $6.91 in the same period a year ago. As in Q1/06, coal generation availability was robust in Q1/07, averaging 93% and falling below 5000 MW approximately 14% of the time – a substantial improvement over last quarter but underscoring the exceptional availability level for coal generators in Q1/06.



Also contributing to softer Q1/07 prices were favorable import fundamentals. At the Mid-C trading hub in the Pacific Northwest, prices were down particularly in the month of March due to seasonally high water levels. Dams on the Columbia River hydro system were forced to spill water on certain occasions. Flush hydro conditions resulted in an average on-peak Alberta – Mid-C price differential of $16.73/MWh through Q1/07. A countervailing effect was the substantial improvement in available transmission capacity (ATC) for exports to BC in Q1/07 to an hourly average of 346 MW from an hourly average of 35 MW in Q1/06. This provided enhanced ability for traders to flow energy in off-peak hours and thus partially explains why Q1/07 off-peak pool prices were not

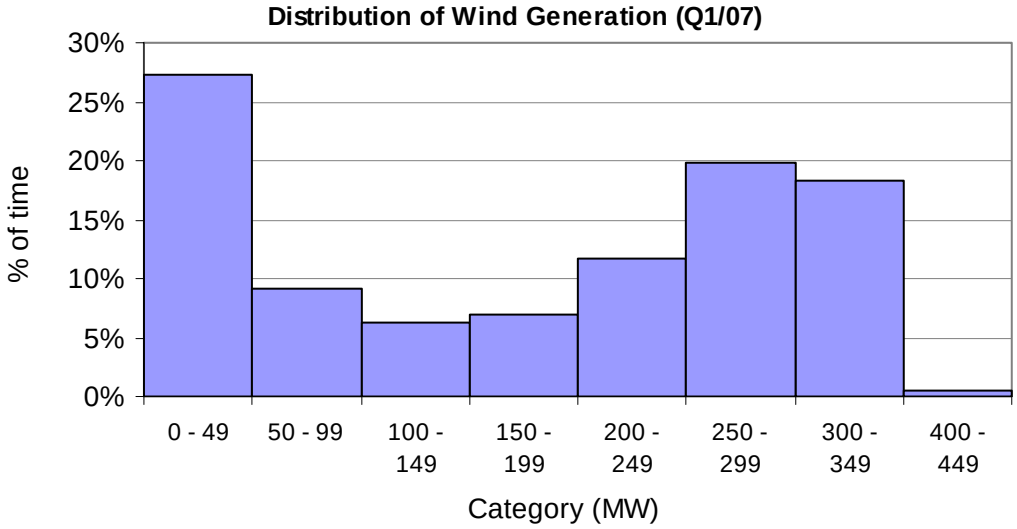
quite as soft as year-ago prices. Periods of lower coal generation availability in Q1/07 relative to Q1/06 contributed to the year over year difference in on-peak prices.

1.2 Wind Developments

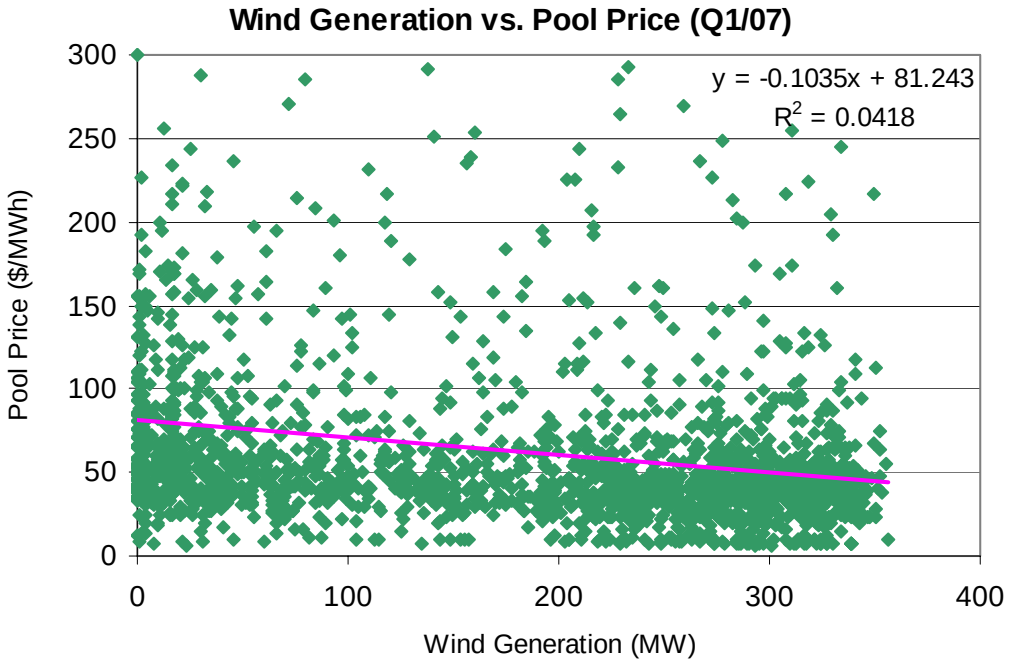
Wind generation currently comprises a modest but rapidly growing segment of the Alberta market. With the recent commissioning of Enmax Taber, a total of 440 MW of wind energy is now connected to the Alberta system comprising nearly 4% of installed generation capacity. The integration of wind has been a key issue for the market operator in recent years – more so recently. A challenge exists in balancing the desire for greater wind integration against the need for tools and procedures to mitigate system reliability risk associated with a significant wind component – principally, the inherent uncertainty and variability of wind output. System stability and reliability considerations take on greater significance as the penetration of wind power increases. Determination of appropriate mitigation measures and the responsibility for their cost remain the key issues of the day. Until these have been resolved, an upper limit of 900 MW has been applied to total installed wind generation. Installed wind is expected to reach 545 MW by the end of 2007.

In late Q1/07, the AESO held a stakeholder consultation session to outline its approach to large scale wind integration in Alberta while providing stakeholders an opportunity to provide feedback. Currently, a wind forecasting pilot project is underway to compare the reliability of different forecasting methodologies in order to assess their effectiveness. Publication of next steps is expected in Q2/07.

The MSA monitors wind output as a part of its regular market monitoring activities in explaining market fundamentals, and now includes this data in our weekly Market Monitor report. A look at hourly data for Q1/07 overall, indicated the distribution of wind output is somewhat bi-modal in nature where there were concentrated periods with either no generation or strong generation, with less representation in between. This would appear to characterize wind patterns in southern Alberta where wind installations are presently concentrated – at least based on three months of data.

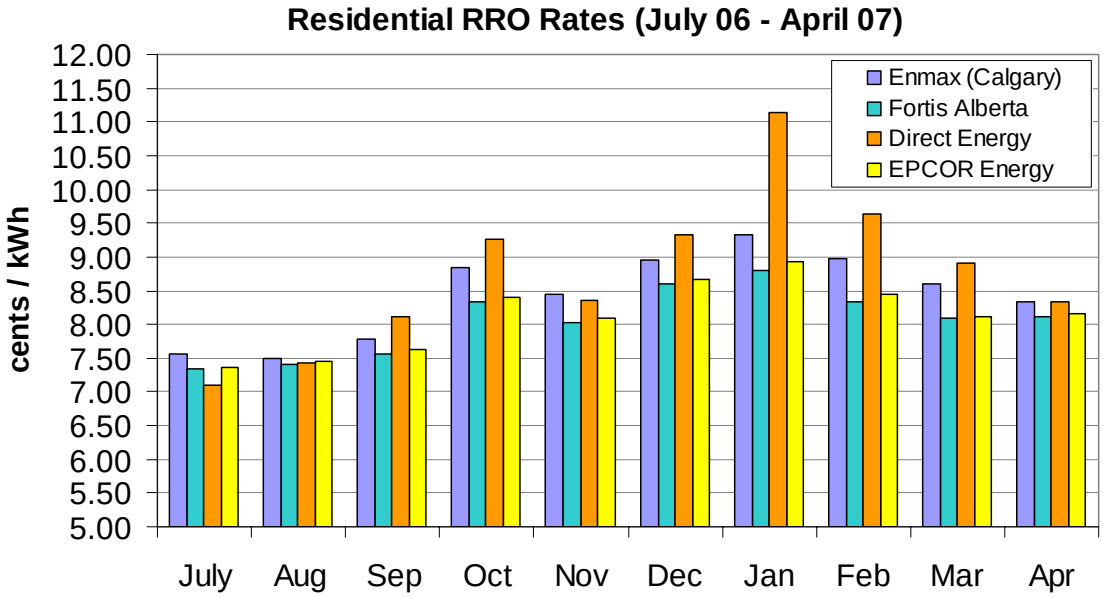


A regression analysis of Wind generation versus Pool price for the same period indicated a weak negative correlation. As might be expected, this result is indicative of a slight price depressing effect of wind in that it is forced to offer at $0.00. This can be contrasted with imports which are similarly constrained to be is offered at $0.00 but are discretional as to when they are scheduled and thus do not show the same pattern.



1.3 RRO

Retail rates under the new rate determination process introduced in Q3/06, peaked in January 2007, however, rates for the various regulated rate providers trended downward through Q1/07. While the market is still in the first year of transition rates (80% long-term hedge basis / 20% short-term hedge basis), the rate peaks observed in January reflect higher cost Q1/07 full load contracts procured in early Q4/06 – a period of enhanced market volatility and scarcity which drove forward energy prices higher. The significant softening of the month-ahead market during Q1/07 has resulted in the subsequent downward trend in rates. Of significance will be the timing of the next round of full load auctions which are expected to get underway in mid-Q2/07.



1.4 MSA Activities

Spring Stakeholder Meetings – The MSA held its spring stakeholder meetings in Edmonton and Calgary on March 27 and 28 respectively. Martin Merritt gave a presentation outlining MSA views on a variety of competitive market issues as well as priorities for the balance of 2007.

Section 6 Committee – During the quarter the MSA has been an active participant in Section 6 committee discussions. This committee of electric industry stakeholders has been established to provide recommendations to the Minister of Energy on what principles should be put in place to further clarify fair, efficient and openly competitive conduct (as specified in section 6 of the Electric Utilities Act) and which regulatory mechanisms and agencies are best suited to ensure market participants adhere to the principles. Phase I of the committees work concluded at the end of March. The committees work is set to continue into Q2 2007 and the MSA remains optimistic that the committee's deliberations will be successful in providing greater clarity to the market and to the MSA.

EISG – Representatives of the MSA recently attended the spring meeting of the Energy Inter-market Surveillance Group – an international association of electricity market monitoring units. This meeting was hosted by the Southwest Power Pool (SPP) in Little Rock, Arkansas. The EISG meets twice annually to discuss competitive electricity market issues of mutual concern and interest.

Investigations – The MSA is currently active on several investigation files although for confidentiality reasons, is unable to comment on their status at this time.

Information Sharing – This MSA project began in late 2006 and progressed through Q1/07. An internal report identified that some larger market participants were using various forms of agreements to offer more MW to the real-time market than their ownership would otherwise dictate. This fact needs to be considered against the backdrop of a publicly stated MSA concern on market concentration. Given the ongoing discussions within the Section 6 Committee, it seems prudent to await some conclusions from that debate before the question of market concentration and the effects of relationships that increase participants' size can be properly assessed.

Further, the report identified various forms of information sharing within agency and joint venture agreements, some of which the MSA believes should be changed and others which, somewhat surprisingly, were more stringent than the MSA might require. On the matter of information sharing within agency and the approval of those and other arrangements, the MSA has begun discussions with the AESO on refining and application of its existing rules in this area.

APPENDIX A – WHOLESALE ENERGY MARKET METRICS

Table 1 - Pool Price Statistics

	Average Price[1]	On-Pk Price	Off-Pk Price	Std Dev[2]	Coeff. Variation[3]
Jan - 07	60.75	74.10	43.81	62.44	103%
Feb - 07	73.38	84.15	59.01	59.48	81%
Mar - 07	56.72	70.72	37.29	62.24	110%
Q1 - 07	**63.29**	**76.32**	**46.70**	**61.83**	**98%**
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%
Q4 - 06	**116.96**	**152.70**	**72.22**	**153.68**	**121%**
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%
Q1 - 06	**56.76**	**70.10**	**40.03**	**43.24**	**76%**

1 - $/MWh

2 - Standard Deviation of hourly pool prices for the period

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

Figure 1 – Pool Price Duration Curves

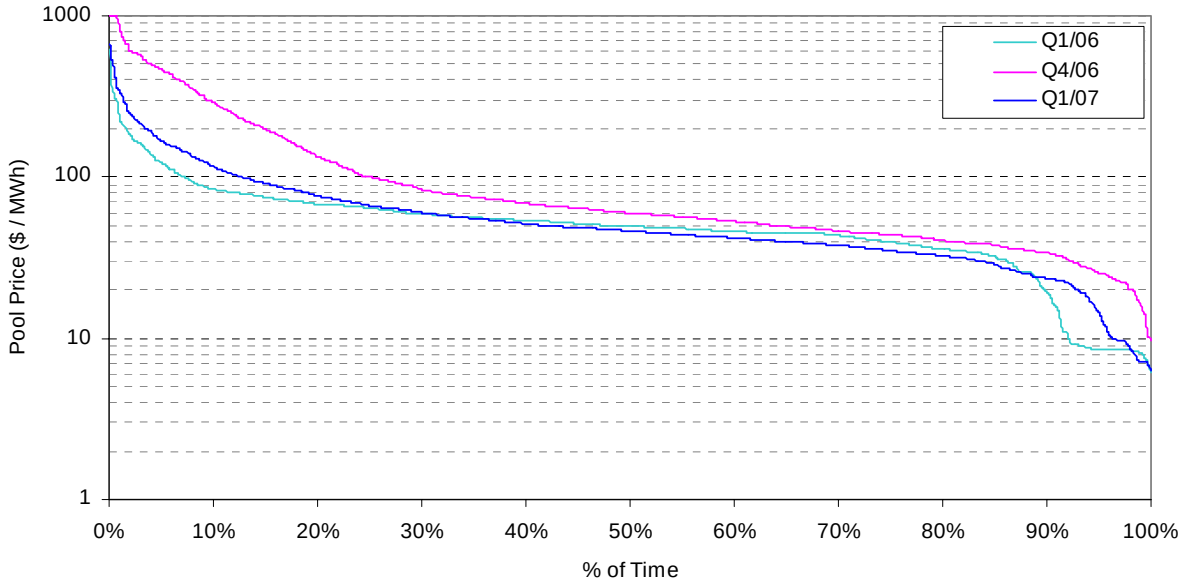


Figure 2 – Pool Price with Pool Price Volatility

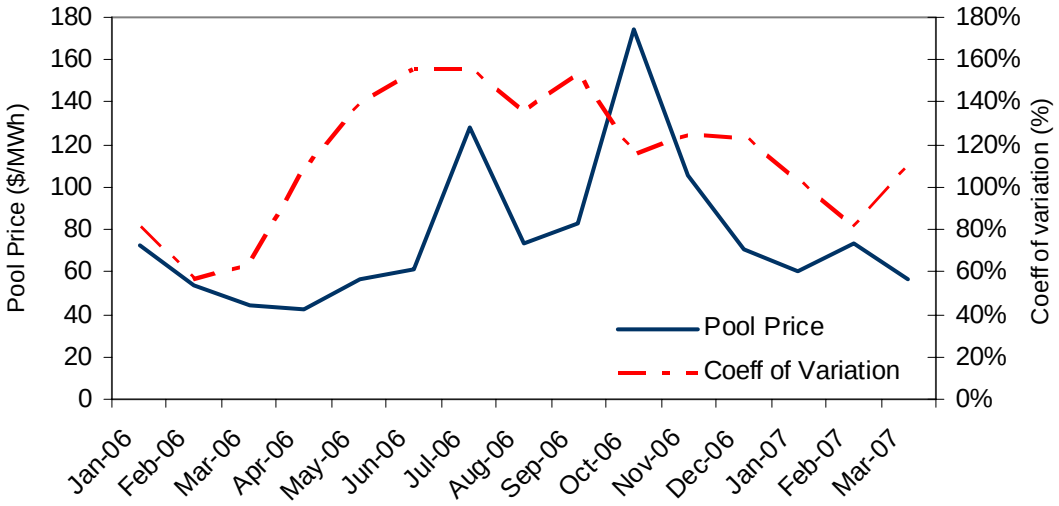


Figure 3 - Wholesale Electricity Price with AECO Gas Price

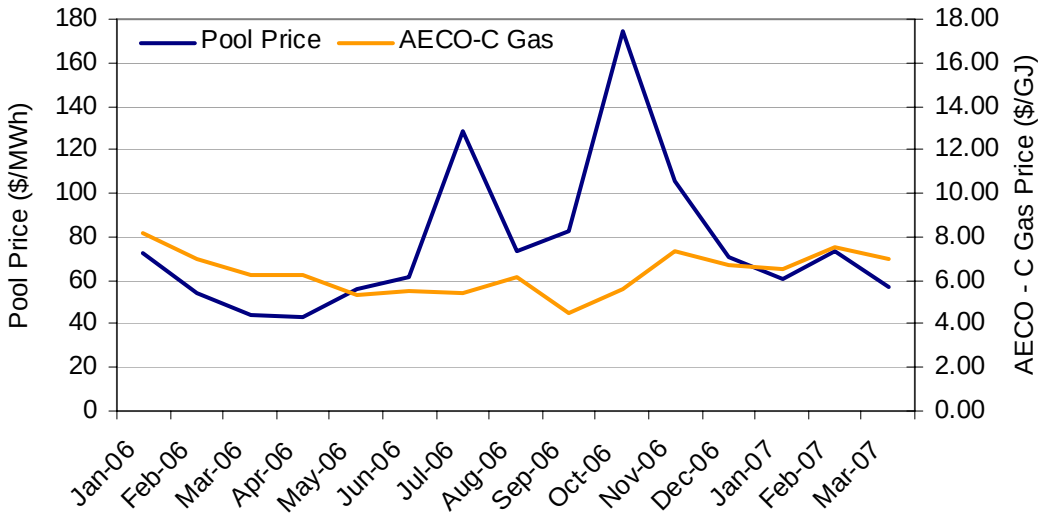


Figure 4 - Price Setters by Submitting Customer (All Hours)

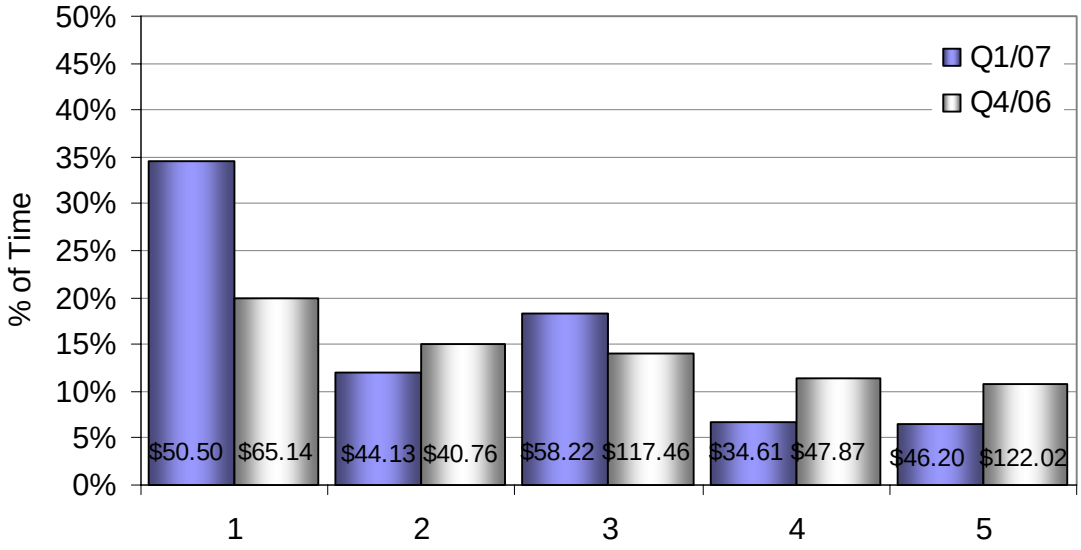


Figure 5 - Price Setters by Fuel Type (All Hours)

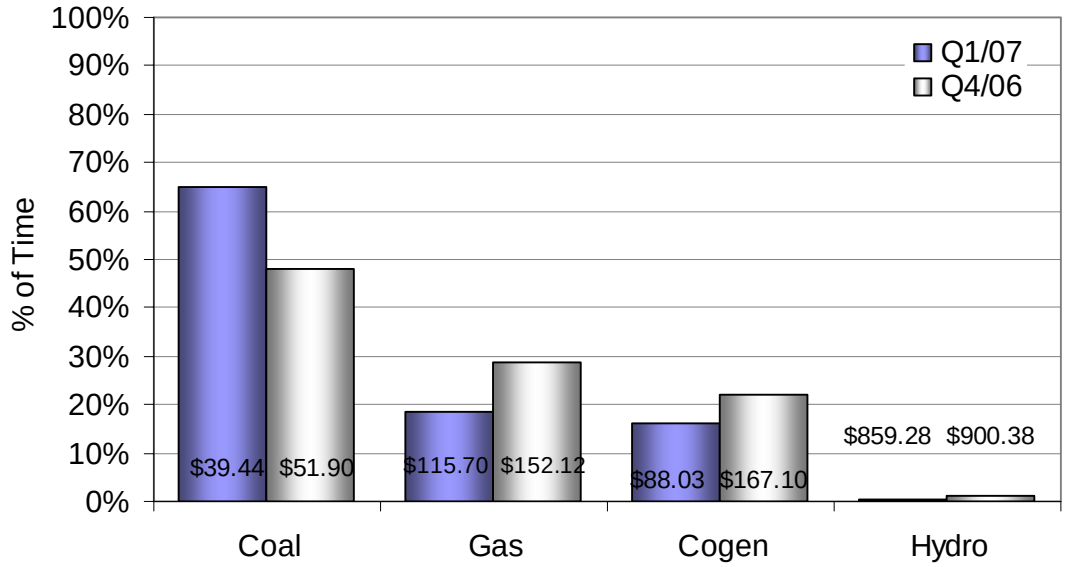
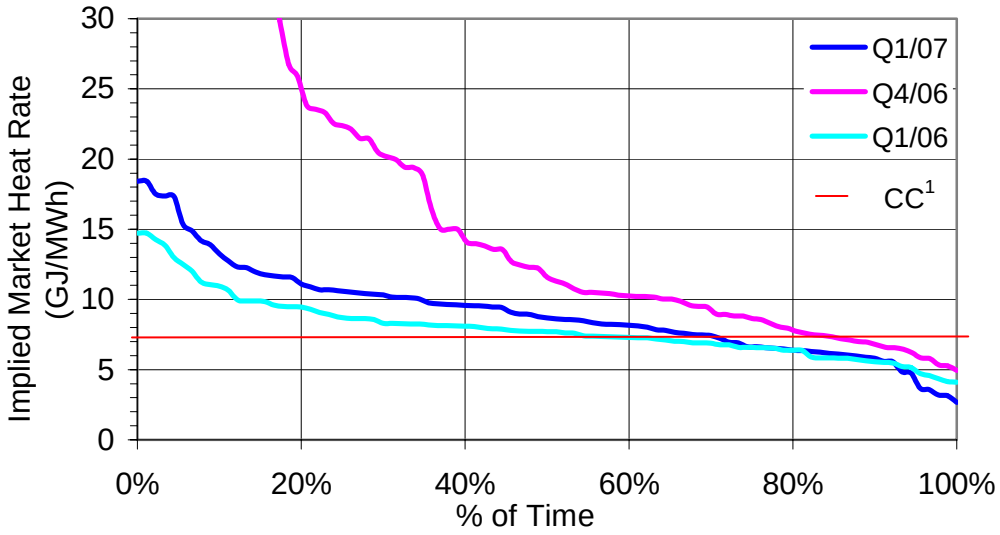


Figure 6 – Heat Rate Duration Curves (All Hours)



1 - CC denotes a representative combined-cycle generator with a heat rate of 7.5 GJ/MWh

Figure 7 - Implied Market Heat Rates (Q1/07)

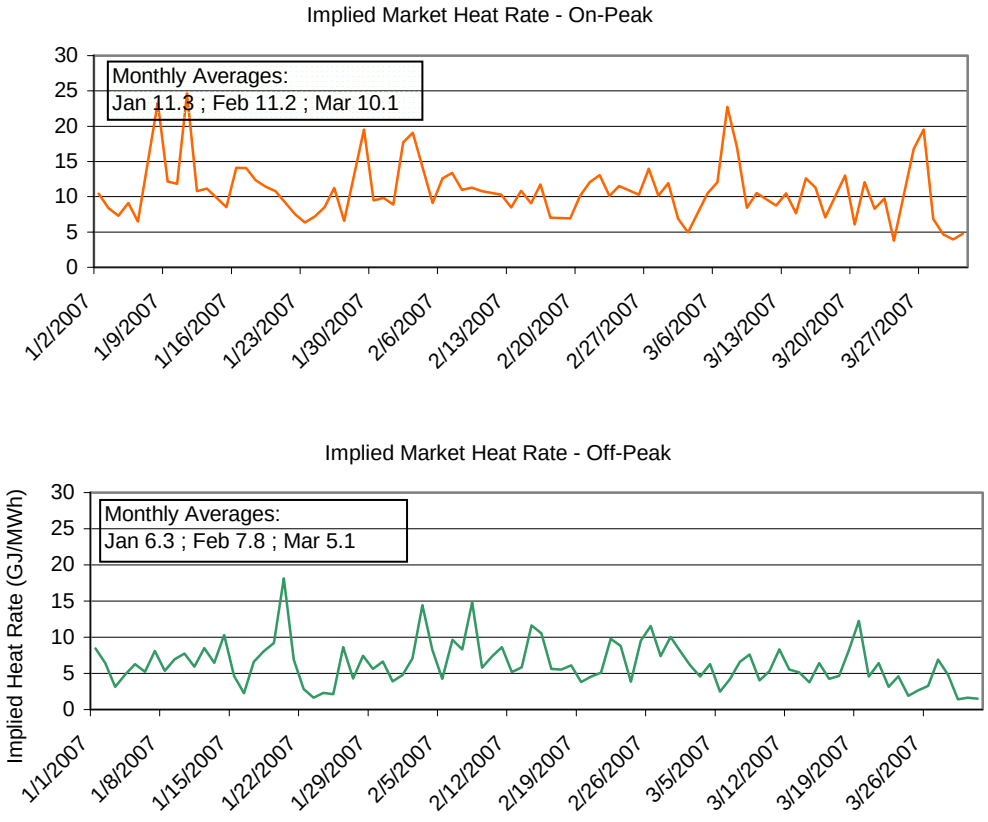


Figure 8 – PPA Outages by Quarter

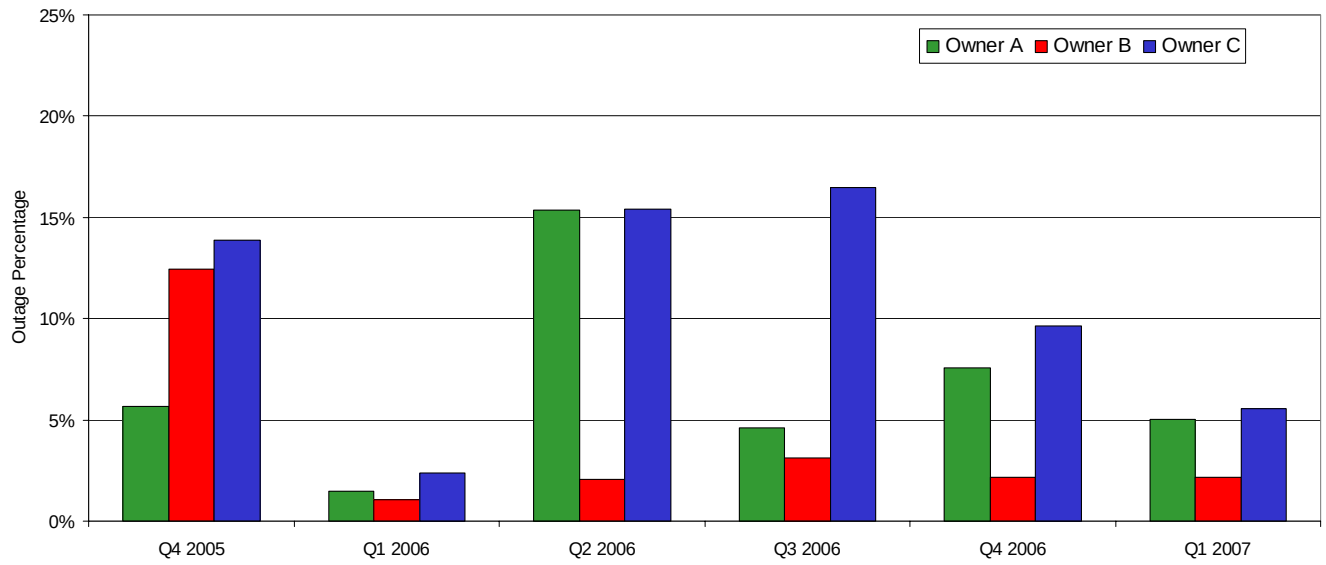


Table 2 - Percentage of Unplanned Outages for PPA Units

	Target Availability 2004	Actual Availability 2004	Target Availability 2005	Actual Availability 2005	Target Availability 2006	Actual Availability 2006	Target Availability 2007	Actual Availability Q1 2007
Owner-A	87%	88%	87%	90%	87%	93%	87%	95%
Owner-B	90%	97%	89%	90%	89%	98%	89%	98%
Owner-C	87%	89%	87%	88%	87%	89%	86%	94%
PPA weighted Average	87%	90%	87%	89%	87%	91%	87%	95%

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

	Q1/07	Q4/06	Q3/06	Q2/06	Q1/06	2006	2005	2004	2003	2002
Owner-A	**4.9%**	7.1%	3.1%	9.3%	1.4%	5.2%	5.0%	6.1%	4.9%	4.2%
Owner-B	**1.6%**	2.1%	2.4%	1.8%	1.0%	1.8%	5.4%	1.5%	1.5%	0.5%
Owner-C	**5.2%**	6.5%	7.9%	4.9%	1.9%	5.3%	6.5%	6.3%	5.7%	10.8%
PPA weighted average	**4.6%**	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.

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 4 – PFEC and PFAM Tracking

Claim Type	Carry-Over	Submitted	Accepted	Rejected	Unresolved	Net kWh Adjustment
PFEC						
Q1/07	15	659	324	331	19	NA
Q4/06	18	304	257	50	15	NA
PFAM						
Q1/07	10	3,275	84	22	3,179	122,942
Q4/06	10	108	72	36	10	(319,236)

Table 5 – Summary of UFE Reasonable Exception Reports

Quarter	Outstanding	New	Resolved	Unresolved
Q1/07	352	1	1	352
Q4/06	267	85	0	352

APPENDIX B – TIE LINE METRICS

Table 6 – Q1/07 Tie Line Statistics

	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	47,839	133,240	(85,401)	28,664	7,691	20,973	76,503	140,931	(64,428)
February	41,843	133,091	(91,248)	9,488	10,002	(514)	51,331	143,093	(91,762)
March	153,432	22,726	130,706	26,282	10,920	15,362	179,714	33,646	146,068
Total	243,114	289,057	(45,943)	64,434	28,613	35,821	307,548	317,670	(10,122)

Figure 9 – Market Share of Importers and Exporters (Q1/07)

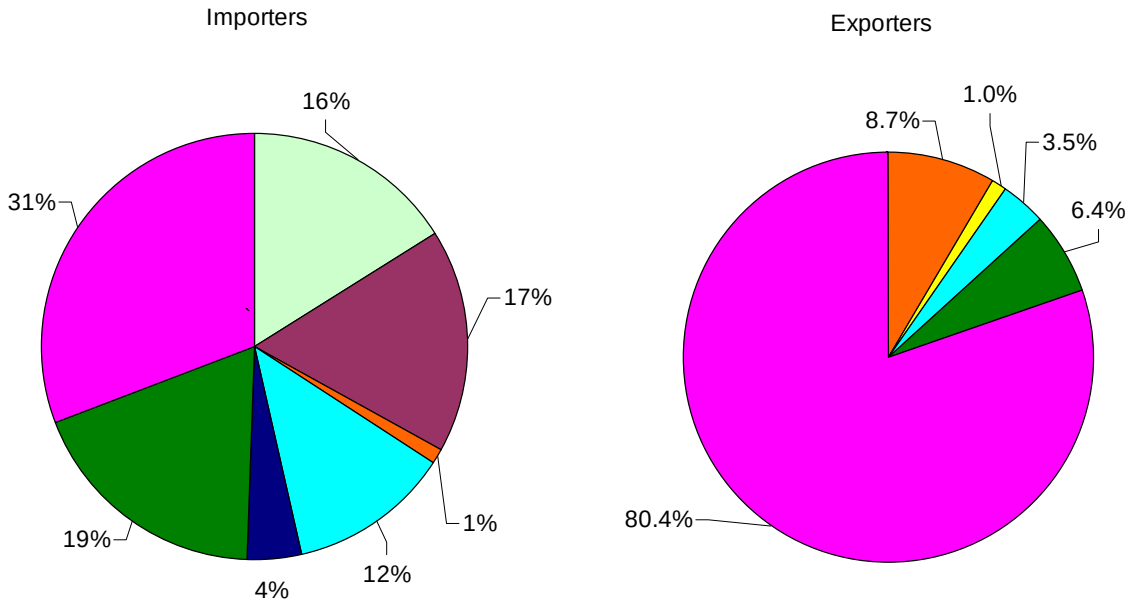


Figure 10 - Tie Line Utilization (Q1/07)

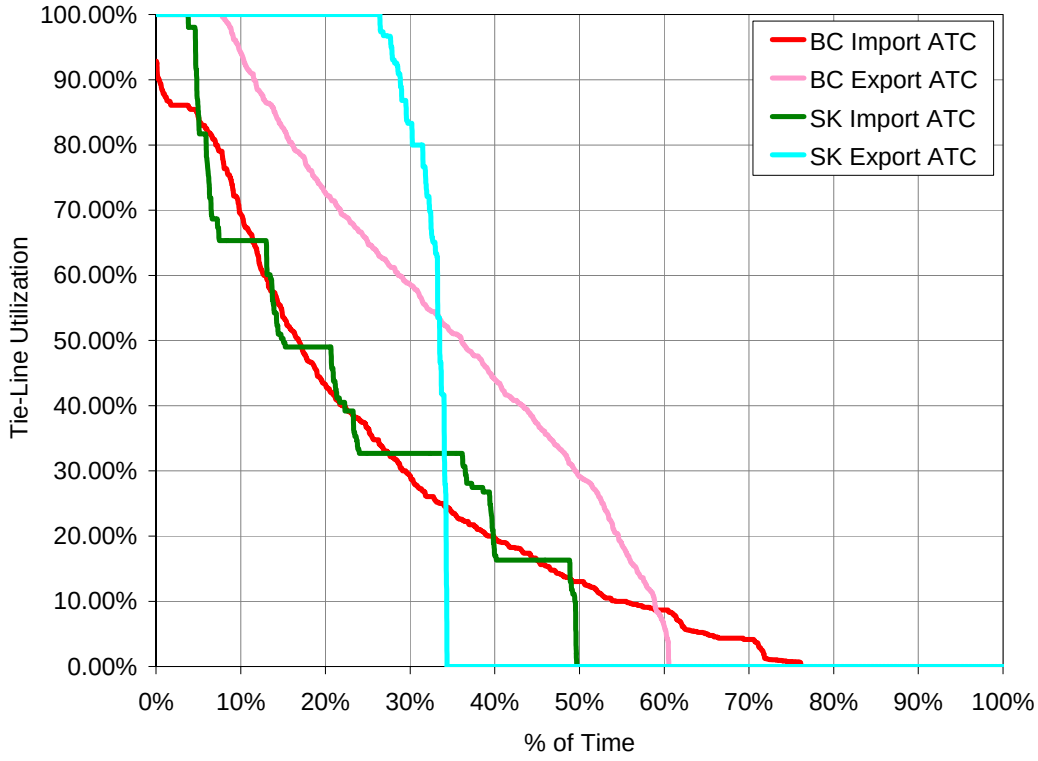


Figure 11 - Imports with Trade-weighted Prices

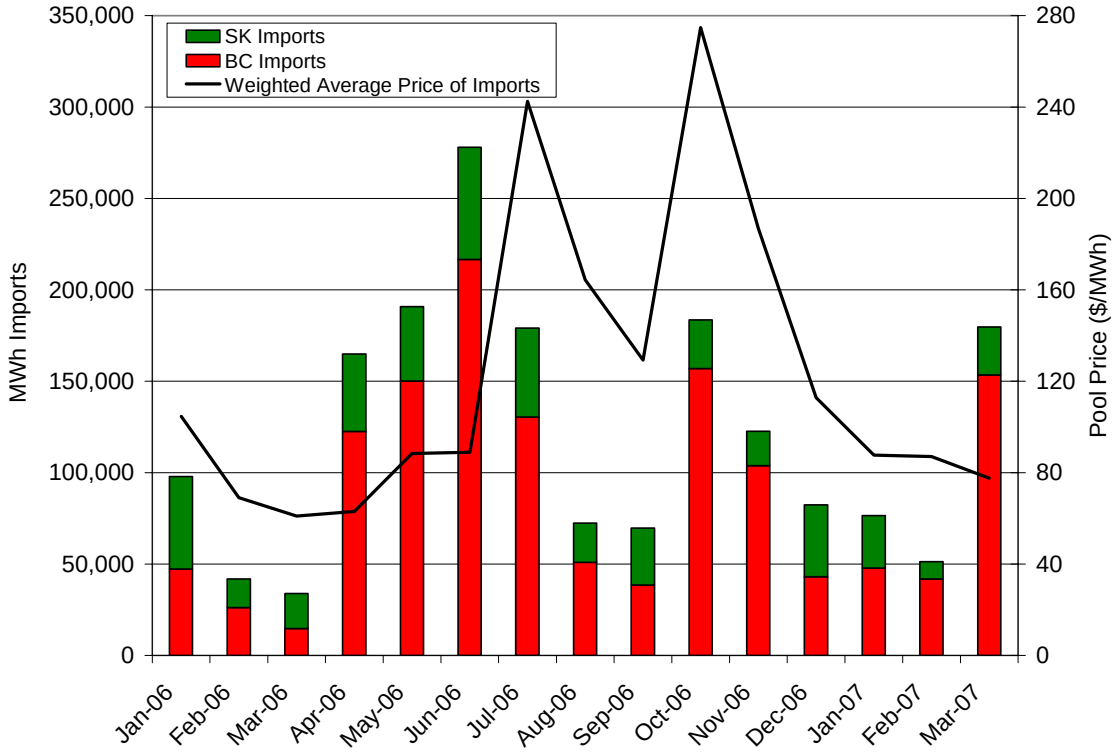


Figure 12 - Exports with Trade-weighted Prices

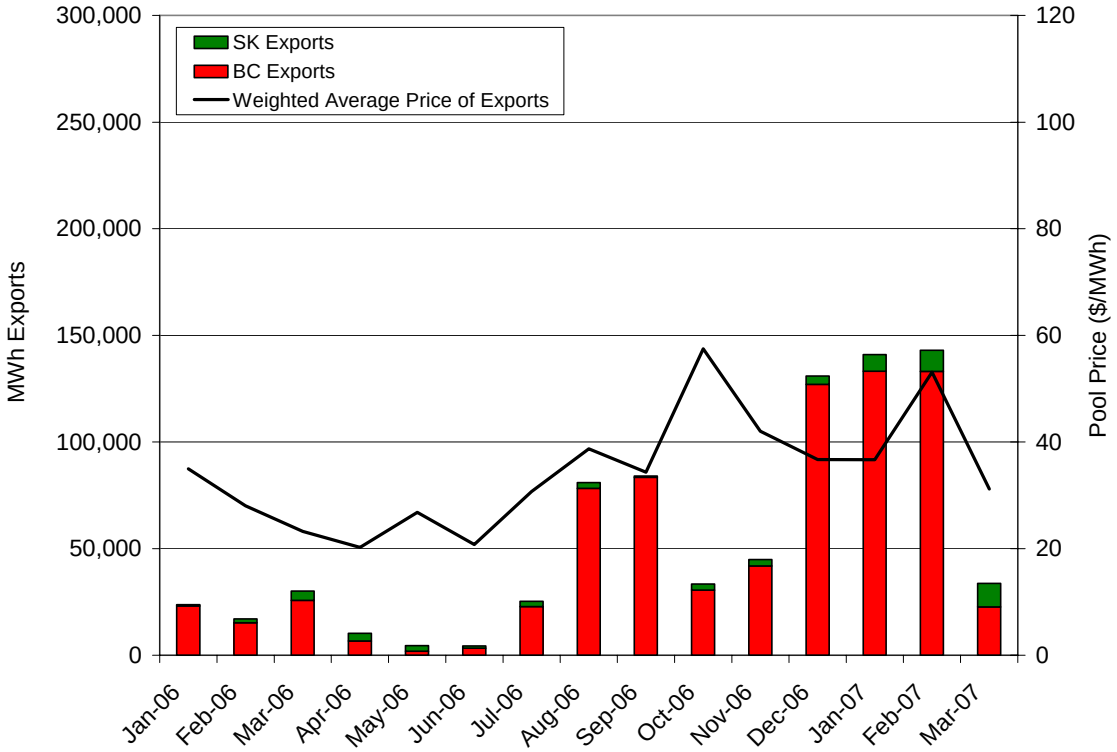


Figure 13 - On-Peak Prices in Other Markets

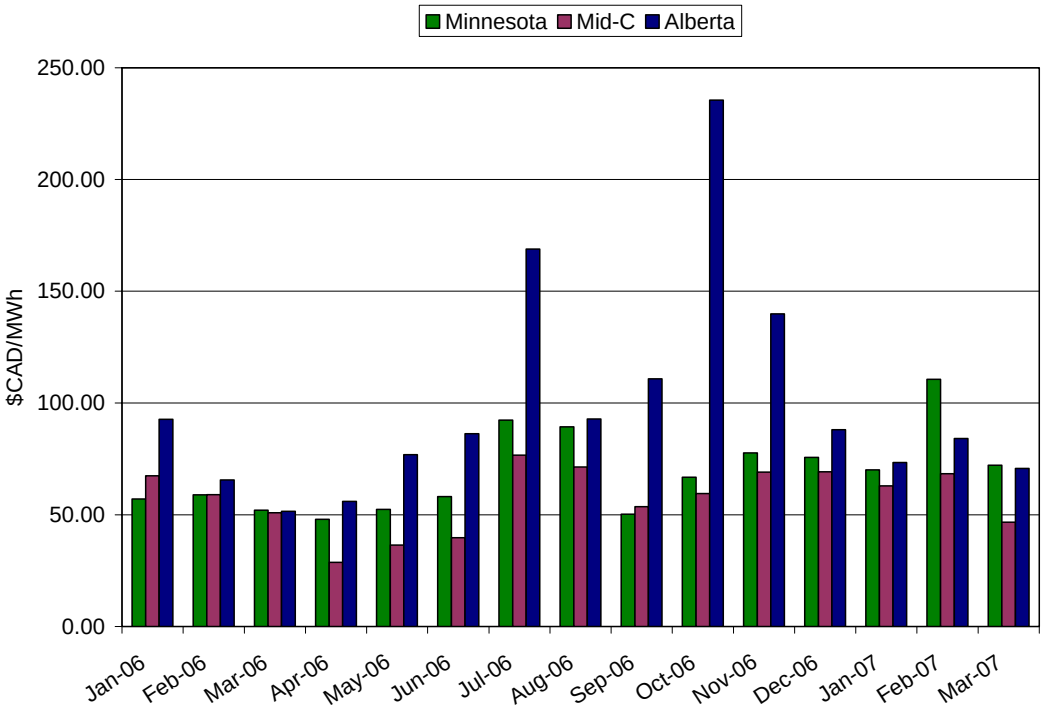
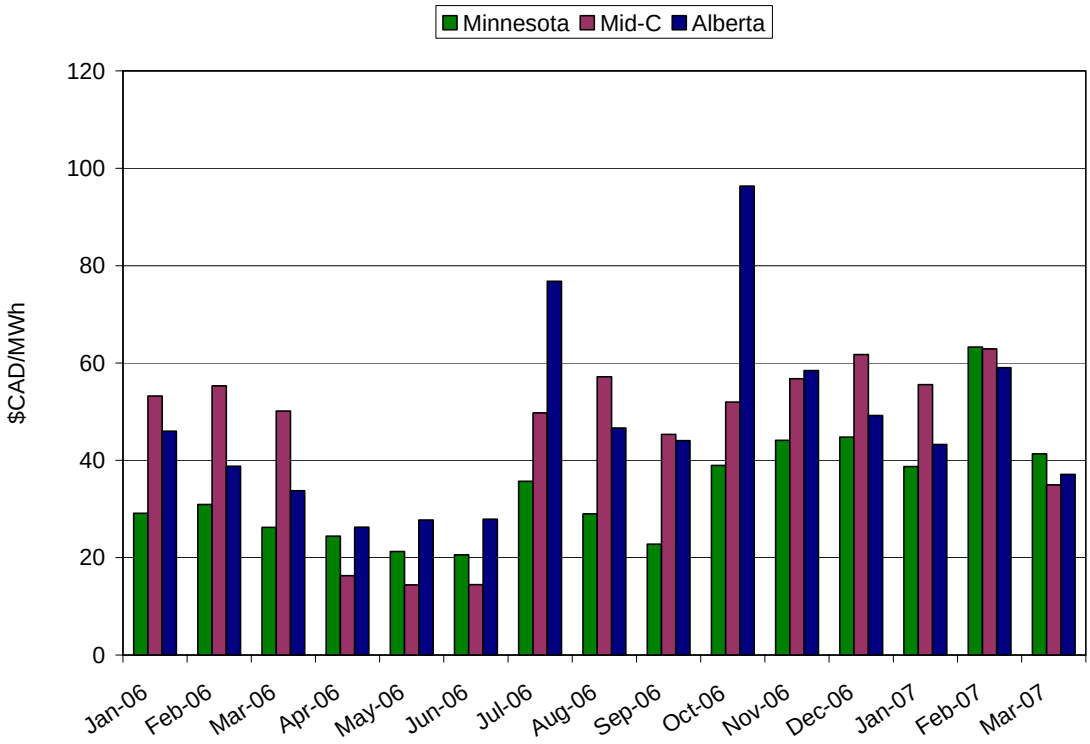


Figure 14 - Off-Peak Prices in Other Markets



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

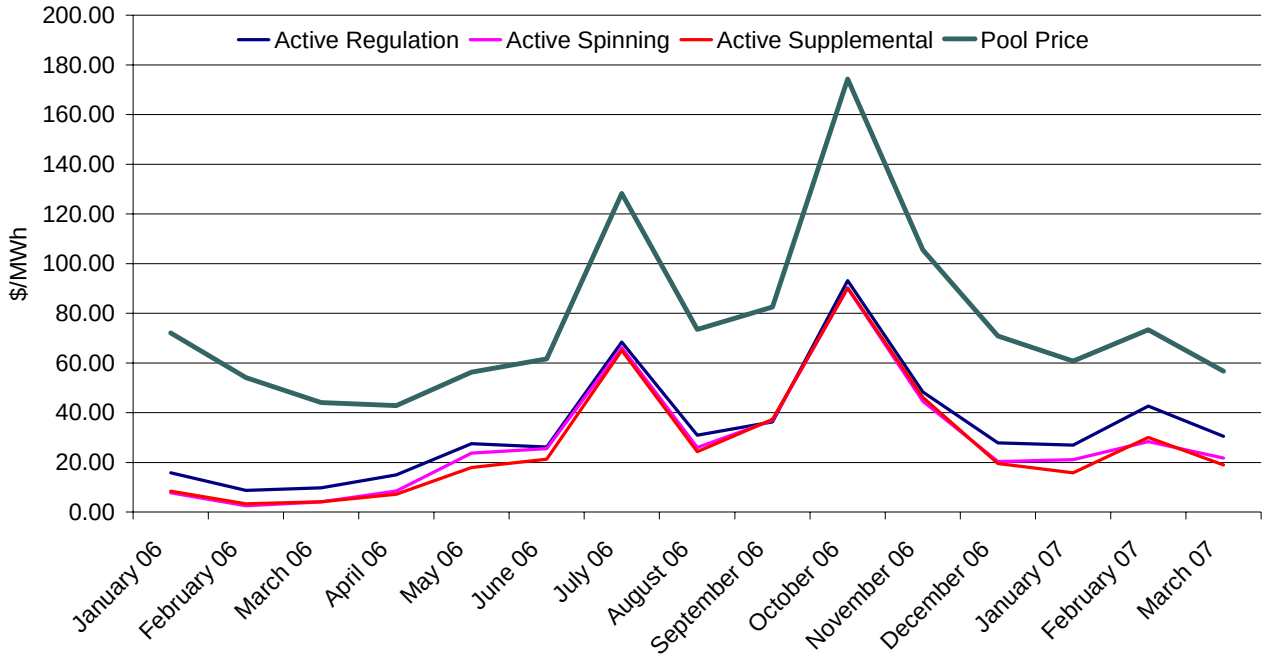


Figure 16 - Standby Premiums - All Markets (Watt-ex and OTC)

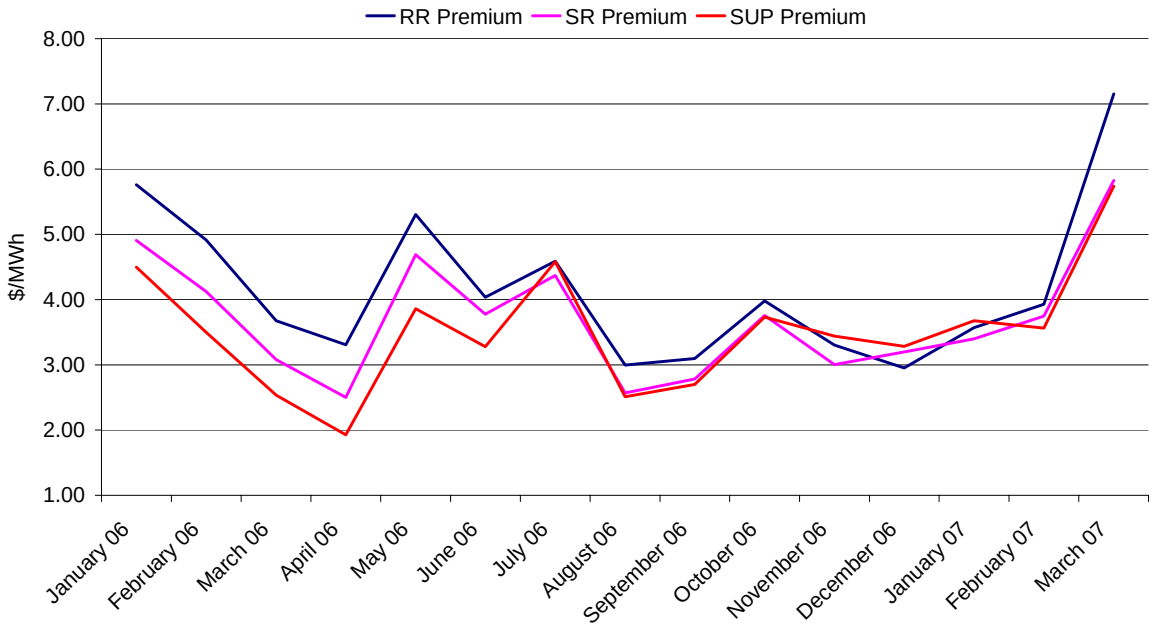


Figure 17 – Activation Prices – All Markets (Watt-ex and OTC)

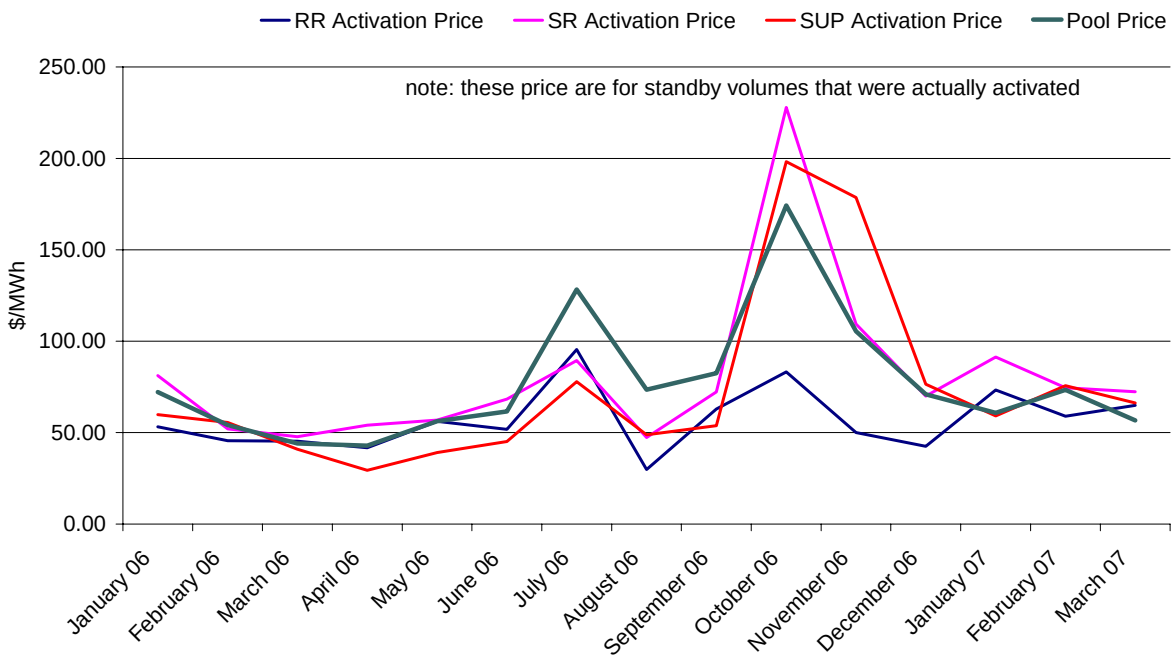


Figure 18 - Standby Activation Rates

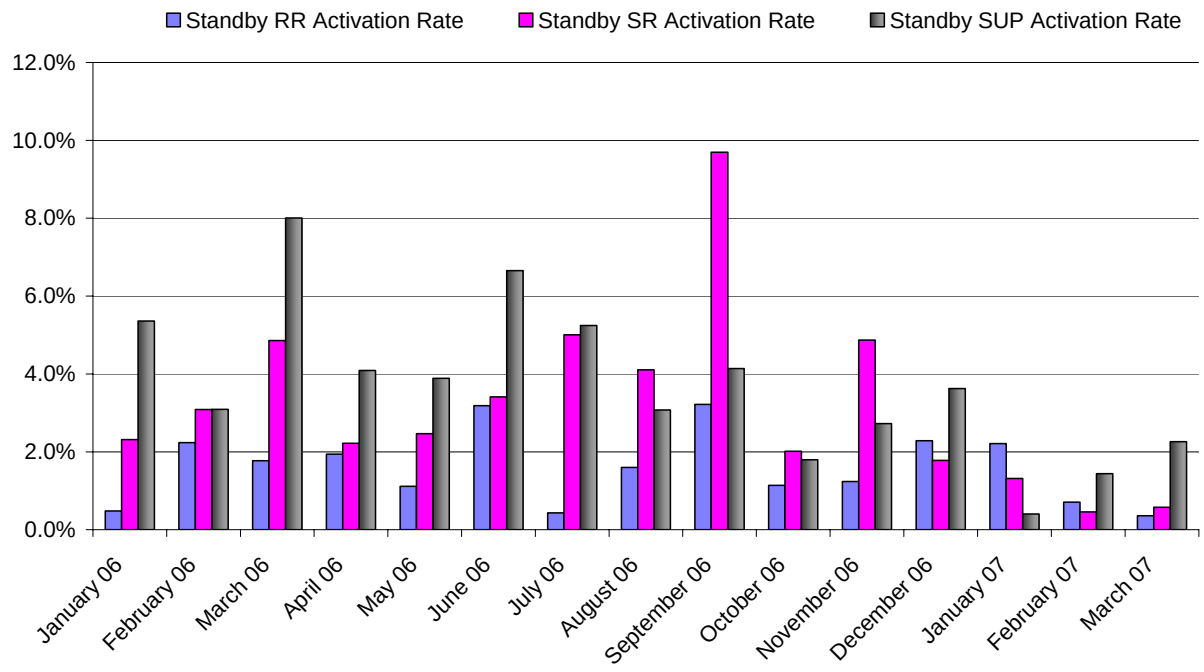


Figure 19 - OTC Procurement as a % of Total Procurement

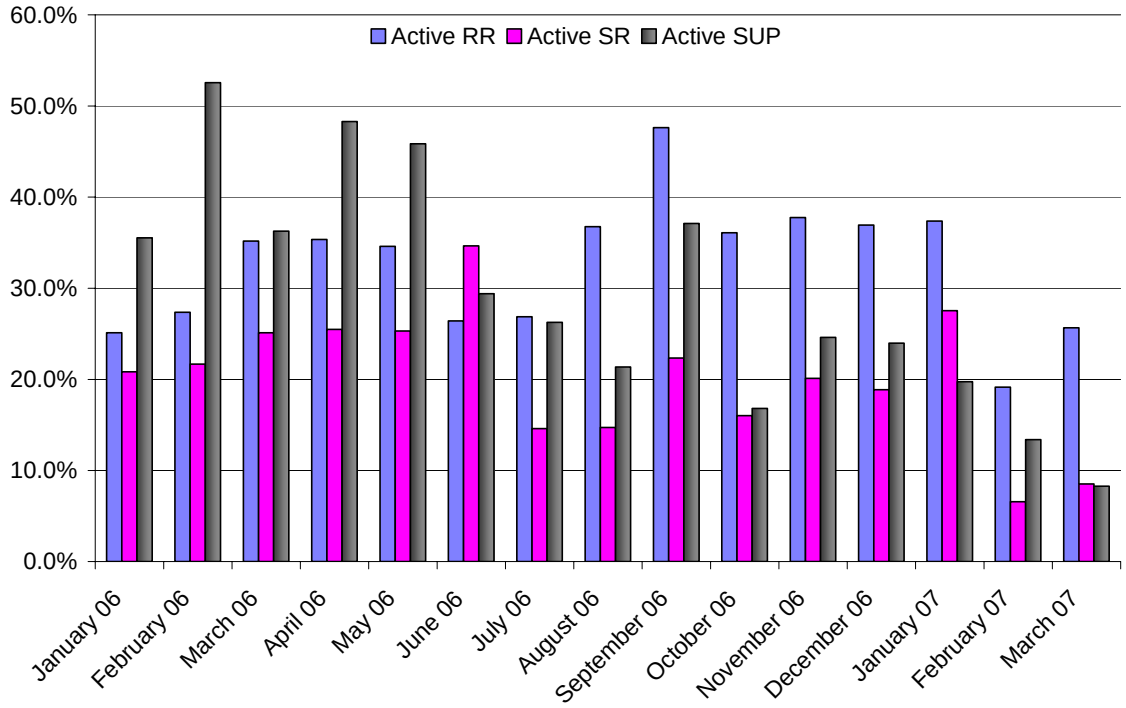


Figure 20 - Active Regulating Reserve Settlement by Market

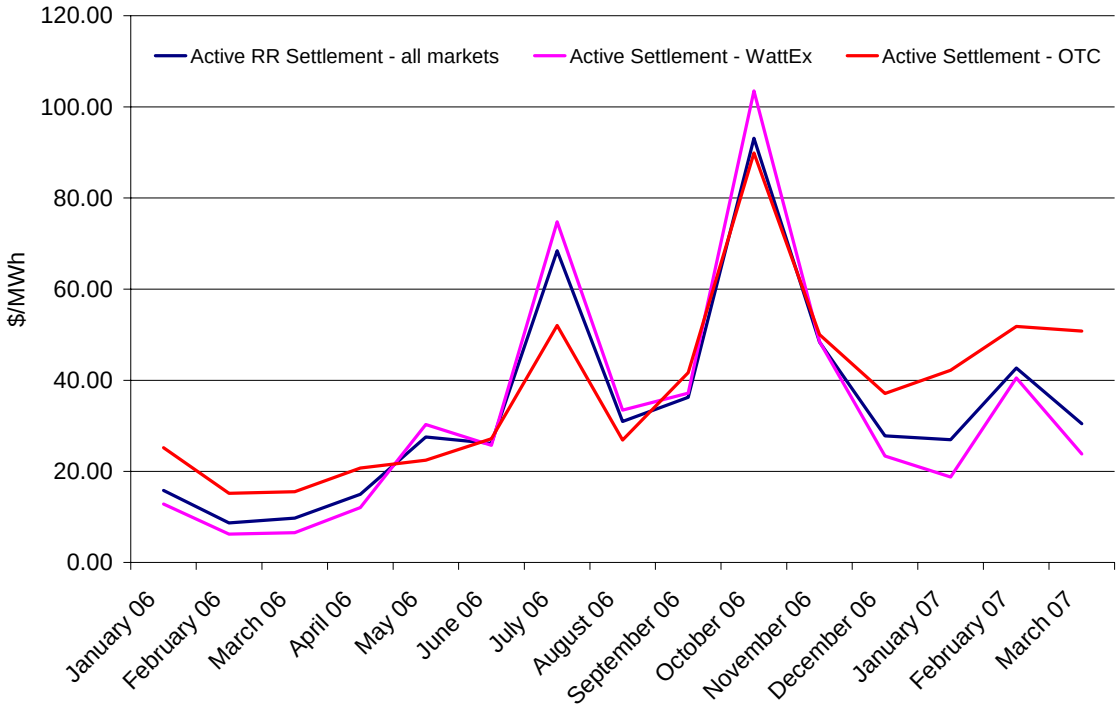


Figure 21 - Active Spinning Reserve Settlement Price by Market

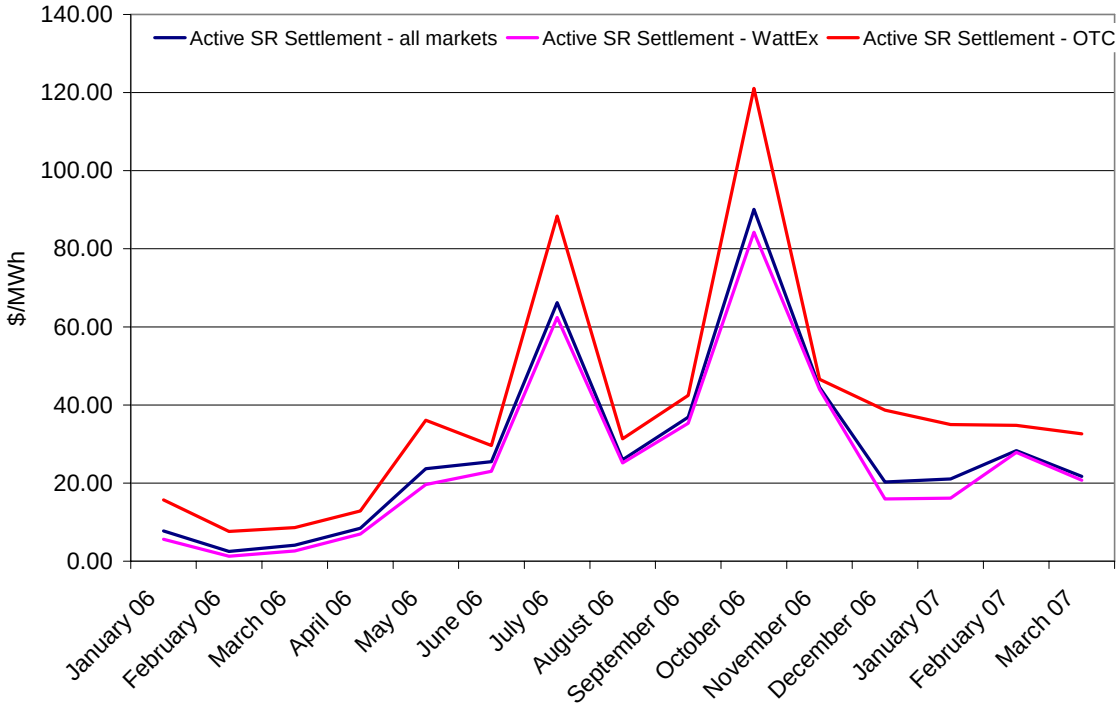


Figure 22 - Active Supplemental Reserve Settlement Price by Market

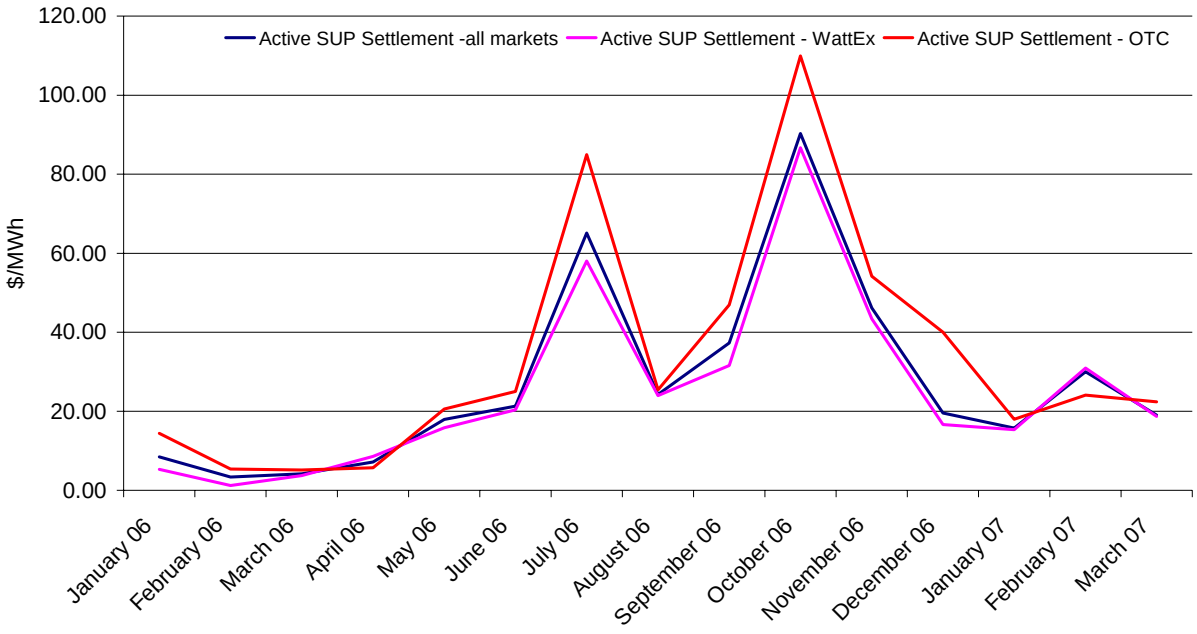


Figure 23 – Active Regulating Reserve Market Share by Fuel Type

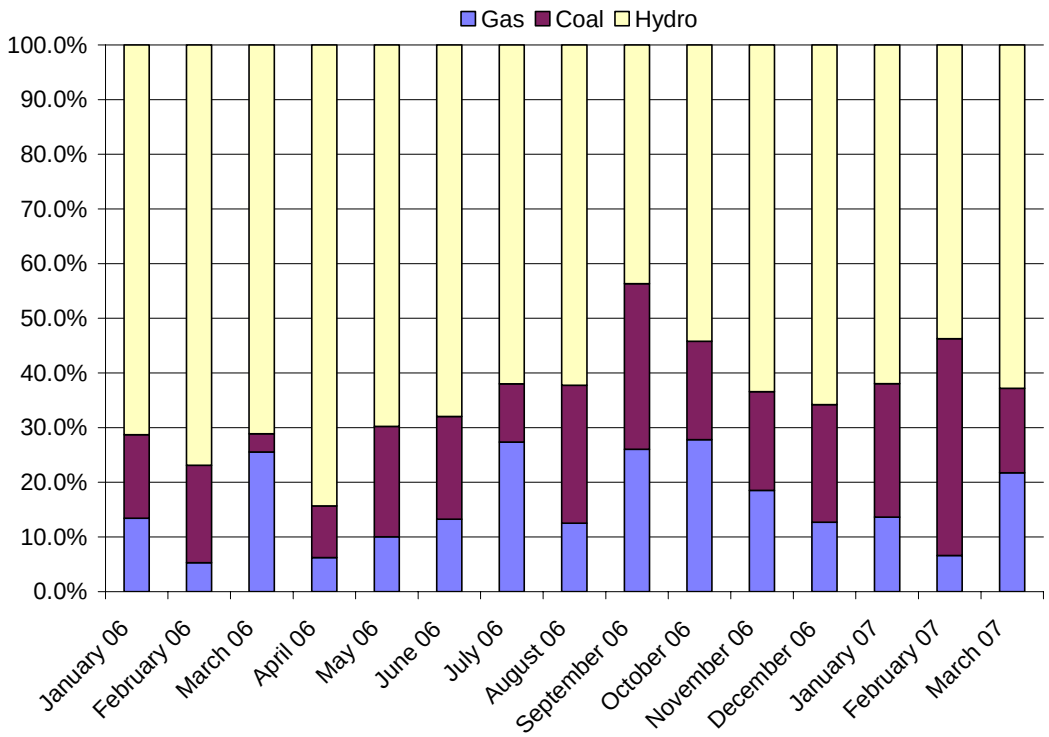


Figure 24 – Active Spinning Reserve Market Share by Fuel Type

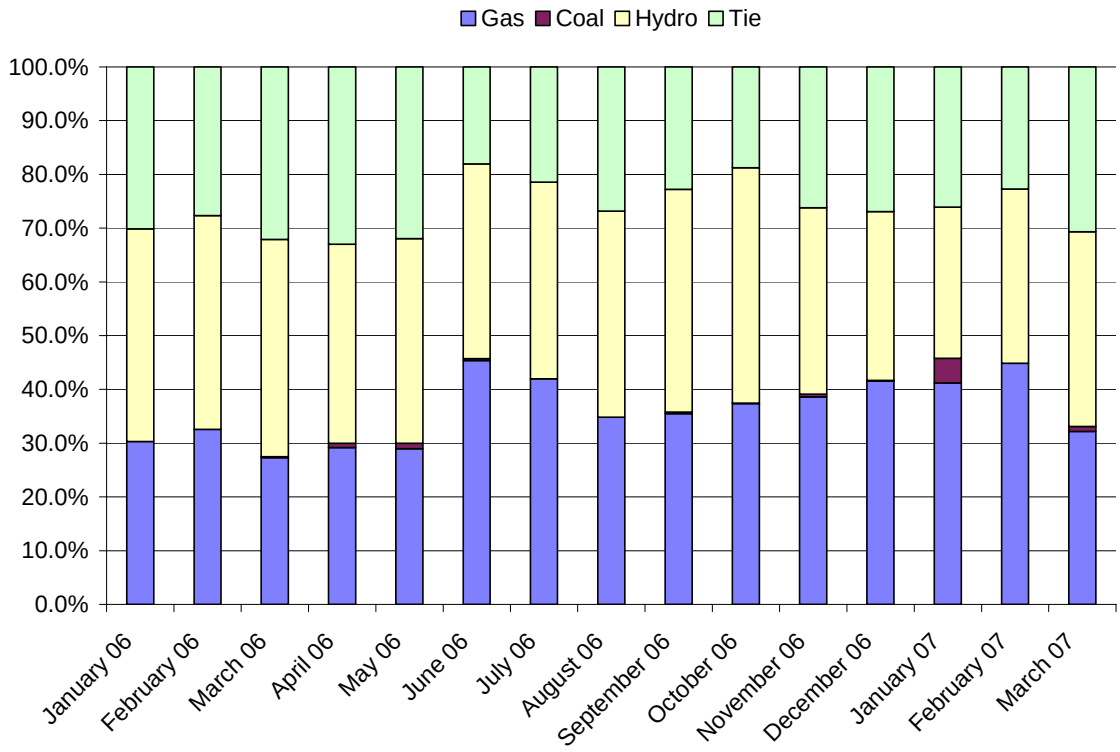


Figure 25 – Active Supplemental Reserve by Fuel Type