

Tabors Caramanis & Associates

**Assessing Deregulated Power
Prices in Alberta: an update to the
2003 report**

Kevin Wellenius

Prepared for the Independent Power
Producers Society of Alberta

September 2004

Executive Summary

In a July 2003 study prepared on behalf of the Independent Power Producers Society of Alberta, Tabors Caramanis & Associates (TCA) presented a comparison of wholesale electricity prices under deregulation and the rates that might have prevailed had Alberta's power industry remained regulated.¹ The study found, among other things, that deregulated wholesale electricity prices ("market prices") were higher than regulated rates would have been during 2001-2003. However, the need to add new generating capacity to meet the province's growing demand would have led to a steady increase in rates, even if the industry had remained regulated.

Competitive market prices, on the other hand, have been on a downward trend due to the introduction of new, more efficient capacity and increased competition in the sector. In the 2003 report we concluded that Alberta was approaching a "crossover point" in which market prices would be less than or equal to the rates under continued regulation. This update to the 2003 report uses current figures, but the conclusion remains the same: prices in Alberta's new competitive market are now or will soon be crossing over with where they would have been if the industry had remained regulated.

In this update to the 2003 report, we revised the calculation of the rates under continued regulation based on current information. In particular, we used updated information on demand, spot and forward electricity prices, and spot and forward prices for natural gas. We observed that the most significant change since the 2003 report concerns the forward prices for natural gas during 2005. As of September 2004, natural gas forward contracts for 2005 delivery were priced at \$6.74/GJ, a nearly 23% increase over the \$5.5/GJ prices quoted in the 2003 report (for 2005 delivery). Higher prices for natural gas mean higher production costs for generators using the fuel. This increase has a stronger impact on market prices than on regulated rates.

Despite the increase in natural gas prices for delivery in 2005, we continue to find that competitive market prices are at or near the "crossover point" relative to the rates that would have prevailed had the market remained regulated. In the "All Gas" scenario – in which all additions to ratebase are assumed to be based on natural-gas fired technology, similar to actual capacity expansion in the province – the crossover occurs in either 2004 or 2005, consistent with the 2003 report. Under the less likely "50% Coal" scenario – in which half of all additions to ratebase are assumed to be coal-fired, and half gas-fired – market prices approach this crossover, but do not achieve it until after 2005.

When considered together with the customer refunds from the PPA Auction, the net customer impact of deregulation for 2001-2005 ranges from a benefit of \$450 million to a cost of \$540 million under the central "All Gas" case. Under the less likely "50% Coal" case, this net impact is a cost of \$0.9 – 1.9 billion. Compared to energy costs of approximately \$17 billion over the same period, this represents a maximum customer cost of 3.2% in the "All Gas" case, and 11.2% in the "50% Coal" case.

¹ K. Wellenius and Seabron Adamson, "Is the Restructuring of Alberta's Power Market on the Right Track? Evaluating Alberta's First Two Years of Deregulation." Prepared for the Independent Power Producers Society of Alberta (IPPSA). July 2003. http://www.ippsa.com/pdfs/dereg_study.pdf

The assessment of whether Albertans pay more for electricity under competition or regulation will continue to vary depending on the evolving price of natural gas. However, it is important to recognize the very tangible benefits already secured by deregulation:

- over 3,000 MW of new capacity has been built, meeting demand growth and improving reliability;
- new capacity is being built through private investment, not at ratepayer risk;
- average market heat rates continue to decline, reflecting continued operational improvements, the effect of competitive pressure on prices, and the addition of modern and efficient new generating capacity; and
- new technologies – especially wind power – are flourishing now that a robust marketplace exists for their output.

This analysis shows that, over the period 2001-2005, customers would not have been financially better off if Alberta's generation expansion had occurred under regulation rather than competition. Moreover, the continued trend of improved market efficiency will yield sustained benefits compared to rates under continued regulation, as the latter would have continued to increase to pay for a swelling ratebase.

The analysis also shows that, with the benefit of hindsight, rates under continued regulation could have been lower than market prices had the province's central planners embarked on an ambitious program to build 2,000 MW of new coal-fired capacity by 2005. However, it is by no means certain that this much coal capacity could have received regulatory approval and been constructed within the needed time frame. In addition, experiences in other markets, such as Ontario, show that central planning has its risks and, as such, has a potential for dire cost implications to consumers as well.

Changes since the 2003 report was prepared

The 2003 report was completed in July, and included projections of wholesale prices, natural gas prices, and load growth for the rest of 2003 as well as 2004 and 2005. A summary of the prices at the time of the 2003 report, as well as current prices, is shown in Table 1.

The 2003 report expected that wholesale market prices would be approximately \$64.5/MWh in 2003, based on Power Pool prices in the first half of the year, and forward prices for the remainder. Actual Power Pool prices for 2003 averaged \$64.7/MWh. For 2004, two projections were used. First, forward market prices² for 2004 of \$47.8/MWh were considered. This implied an extremely low average market heat rate³ given that forward natural gas prices were approximately \$6/GJ. As an alternative benchmark, we estimated that electricity prices of

² "Forward market prices" are prices that are offered by suppliers for term sales in the days, months, or years ahead. Forward market prices used in this study were sourced from Chase Energy Canada Limited.

³ "Market heat rate" is equal to the price of power divided by the price of natural gas. This metric demonstrates how efficiently the market is performing in terms of GJ/MWh, and can be applied either to spot or forward markets.

approximately \$56.2/MWh would be more consistent with such a gas price. For the year through August 31, 2004, average demand-weighted electricity prices have actually been \$55.5/MWh. While this would suggest that the “Market Heat Rate” benchmark proved more appropriate, we note that actual natural gas prices have been \$6.26/GJ. In other words, actual electricity prices have been slightly *lower* than the MHR benchmark despite natural gas prices that have been *higher* than those on which the benchmark was based.

For 2005, current forward electricity prices are higher than both of the 2003 report’s benchmarks. This is due to forward natural gas prices for 2005 delivery having increased significantly between 2003 and 2004.

The forward market heat rate implied by the relationship between electricity and natural gas forward prices has remained relatively unchanged. At the time of the 2003 report, the average market heat rates were 7.67 GJ/MWh and 7.72 GJ/MWh for 2004 and 2005, respectively. As of September 2004, the average heat rate implied by 2005 forward prices is 7.74 GJ/MWh.

Finally, peak demand for 2003 had been projected at 8,827 MW; actual peak demand was 8,786 MW.⁴ Total load for 2003 had been projected at 63,015 GWh, whereas actual load for 2003 was 62,714 GWh. The availability of actual 2003 data allows us to base our estimates of rates under continued regulation on more recent information.

Table 1. Electricity and Natural Gas prices, 2003 report and current

	2003	2004	2005
Electricity Prices (Demand Weighted)			
2003 Report			
<i>Forward Market Benchmark</i>	\$64.48	\$47.84	\$44.20
<i>MHR Benchmark</i>	\$64.58	\$56.16	\$51.48
Actual (Sep. 2004)	\$64.73	\$55.54	\$54.28
<i>Year to Date</i>		\$55.47	
<i>Balance of Year</i>		\$55.68	
Natural Gas Prices			
2003 Report	\$6.90	\$6.00	\$5.50
Actual (Sep. 2004)	\$6.30	\$6.27	\$6.74
<i>Year to Date</i>		\$6.26	
<i>Balance of Year</i>		\$6.29	

Note: Electricity prices are demand-weighted averages. Since forward contracts are for baseload energy, the prices have been increased by 4% - the approximate relationship between shaped and baseload Power Pool prices.

⁴ Alberta Energy’s *Key Numbers* reports a peak demand of 8,967 MW for 2003. However, this refers to the “climactic year”, not the calendar year. According the AESO data, this peak occurred January 26, 2004. We used the calendar-year peak of 8,827 MW in this analysis.



Revised estimate of rates under continued regulation

Given revised values for 2003 demand and natural gas prices, we updated our estimate of the regulated rates that would have been necessary to fund capacity additions if generation had remained regulated. We refer to these as the “rates under continued regulation,” since they are the rates that we expect would have prevailed had Alberta’s power industry continued to be regulated. Any attempt to estimate rates under continued regulation requires assumptions about the amount and cost of new capacity. As in the 2003 report, we developed two scenarios of new investment:

- All Gas – In this scenario, all additional capacity is new combined-cycle gas turbine (CCGT) facilities.
- 50% Coal – In this scenario, 50% of new capacity requirements are met by new CCGTs, and 50% through new coal-fired facilities.

The “All Gas” scenario is very similar to the gas-based expansion that has actually occurred in Alberta under deregulation. It therefore offers a scenario of regulated rates required to achieve a capacity expansion similar to actual experience, but through continued regulation rather than through competitive markets. The “50% Coal” scenario represents a very different choice in generation technology, and one which is less likely to have developed. The “50% Coal” scenario implies that approximately 2,000 MW of new coal-fired capacity would have been built by 2005. Currently, the 455 MW Genesee 3 project is the only new coal capacity actually under construction, though upgrades at Keephills and Sundance are also planned to add 190 MW in 2005.⁵ Moreover, to meet the “50% Coal” additions, Alberta would have had to initiate construction of its new coal facilities in the early to mid-1990s. As the Market Surveillance Administrator stated recently, this would require:

[t]hat regulators and legislators would have been clairvoyant enough to begin construction of 3000MW of coal fired generation before the wrangling over Genesee’s construction had even died down at a time when all across North America no one was building anything but gas fired! ...[this] feel[s] like a bit of a stretch to me!⁶

The “All Gas” scenario is, in our opinion, the more likely scenario, while the “50% Coal” scenario is provided to indicate the range of outcomes if a very aggressive policy of coal-based capacity additions been undertaken.

All assumptions are unchanged from the 2003 report, with the exception of natural gas prices and 2003 demand, as discussed above. The reader is referred to that report for a full explanation of the methodology and assumptions.

⁵ Alberta Energy *Key Numbers*, August 2004: <http://www.energy.gov.ab.ca>. Genesee Unit 3 net capacity from <http://www.epcor.com/Tariffs+and+Regulatory/G3/default.htm>

⁶ Comments of the Market Surveillance Administrator, prepared for 2004 IPPSA Conference, page 2. <http://www.albertamsa.ca/files/IPPSA2004wnotes.pdf>

The resulting rates under continued regulation are shown in Table 2, together with the results of the 2003 report calculation. The slightly lower 2003 rates reflect natural gas prices that ended the year lower than expected, whereas the higher 2005 rates reflect the increase in gas prices discussed above.

Table 2. Rates under continued regulation, 2003 report and current

	All Gas			50% Coal		
	2003 report	2004 update	% change	2003 report	2004 update	% change
2001	\$45.91	\$45.91	-	\$42.40	\$42.40	-
2002	\$43.91	\$43.91	-	\$42.26	\$42.26	-
2003	\$54.03	\$52.16	-3.4%	\$47.35	\$46.51	-1.8%
2004	\$54.07	\$53.10	-1.8%	\$48.09	\$47.20	-1.8%
2005	\$53.33	\$56.69	6.3%	\$48.10	\$49.47	2.8%

Note: As in the 2003 report, rates include adjustments for Interconnection charge of STS (\$2.44/MWh) and for the operating reserves charge (3.5%). Both of these are charged against generator output, and are inflated by 1/(1-8.25%) to account for losses of 8.25%

As an additional sensitivity analysis to the input assumptions we have also calculated these rates based on a recent Market Surveillance Administrator (MSA) study of new-entry economics.⁷ The capital cost for coal and CCGT plants are lower than in our analysis. However, this is more than offset by higher fixed O&M costs, a higher heat rate for CCGTs, and higher variable operating costs for coal plants. The estimated rates under continued regulation using our base case new entry assumptions, as well as under the MSA sensitivity assumptions, are shown in Table 3. Overall, the rates under the MSA sensitivity are 4-6% higher than those of our base case assumptions.

Table 3. Rates under continued regulation, (base case assumptions vs. MSA sensitivity)

	All Gas			50% Coal		
	Base	MSA	% change	Base	MSA	% change
2001	\$45.91	\$47.62	3.7%	\$42.40	\$44.35	4.6%
2002	\$43.91	\$45.58	3.8%	\$42.26	\$44.34	4.9%
2003	\$52.16	\$54.63	4.7%	\$46.51	\$49.03	5.4%
2004	\$53.10	\$55.75	5.0%	\$47.20	\$49.90	5.7%
2005	\$56.69	\$59.78	5.5%	\$49.47	\$52.51	6.1%

Note: As in the 2003 report, rates include adjustments for Interconnection charge of STS (\$2.44/MWh) and for the operating reserves charge (3.5%). Both of these are charged against generator output, and are inflated by 1/(1-8.25%) to account for losses of 8.25%

⁷ Market Surveillance Administrator. *Economics of New Entry*. April 2004. Major assumptions are listed in Table 1 of the MSA's report. <http://www.albertamsa.ca/files/EconomicsofNewEntry042804.pdf>

Comparison to market benchmarks

The updated projections for rates under continued regulation can be compared against actual and projected electricity wholesale market prices. This requires developing appropriate benchmarks so that the comparison is valid. As in the 2003 report, for past prices we used demand-weighted average spot market prices as reported by the Alberta Electric System Operator (AESO). For future periods, we relied on recent traded prices for forward electricity contracts, as reported by Chase Energy Canada Limited. Since forward contracts are for baseload (round-the-clock) energy, we estimate a ‘shaped’ price that is analogous to a demand-weighted price by inflating the forward prices by 4%. This multiplier is based on the relationship between demand-weighted and time-weighted (baseload) Power Pool prices for 2002.

In addition to relying on forward electricity prices, we once again developed a Market Heat Rate (MHR) benchmark. In the 2003 report, this alternative benchmark was needed due to an unrealistically low implied market heat rate in the forward markets. At the time, the implied *average* market heat rate was less than 8 GJ/MWh, despite actual market heat rates of 11.3 GJ/MWh in 2002. The average market heat rate implied by current forward gas and power prices for 2005 is 7.74 GJ/MWh. This is below actual recent market heat rates of 10 GJ/MWh in 2003 and 8.7 GJ/MWh in 2004 through August. We have developed a “MHR Benchmark” based on current forward natural gas prices and an assumed average market heat rate of 8.5 GJ/MWh. As with forward electricity prices, this result is inflated by 4% to estimate a demand-weighted price for electricity.

Both the forward market and MHR benchmarks are shown in Table 4. The principal difference is seen in 2005, where the MHR benchmark shows higher prices due to the rise in forward natural gas prices. If actual market heat rates fall below 8.5 GJ/MWh, however, lower prices will prevail at a given price for natural gas.

Table 4. Forward market and MHR benchmarks

Year	Baseload Fwd Elec. Price, \$/MWh	Shaped Fwd Elec. Price, \$/MWh	Fwd Gas Price, \$/GJ	Market Heat Rate, GJ/MWh	Baseload MHR price, \$/MWh	Shaped MHR price, \$/MWh
Sep-Dec 2004	\$53.54	\$55.68	\$6.29	8.5	\$53.46	\$55.59
2005	\$52.19	\$54.28	\$6.74	8.5	\$57.26	\$59.55

Having calculated the rates under continued regulation, as well as having developed appropriate market price benchmarks, it is possible to see which of the two frameworks results in lower overall prices. This comparison is shown graphically in Figure 1 (under our base case assumption for new entry) and Figure 2 (under the MSA sensitivity). Most strikingly, the rates under continued regulation in the “All Gas” scenario using the MSA new entry assumptions were virtually equal to market prices in three of the five years studied in this analysis.

Figure 1. Rates under cont'd regulation vs. market benchmarks - (base new entry costs)

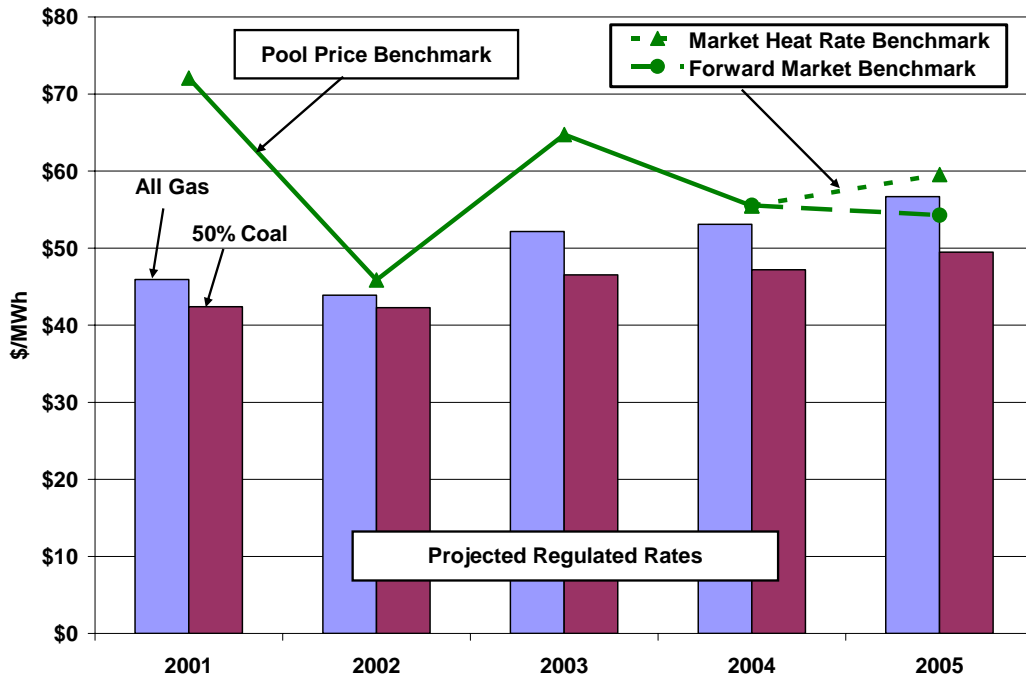
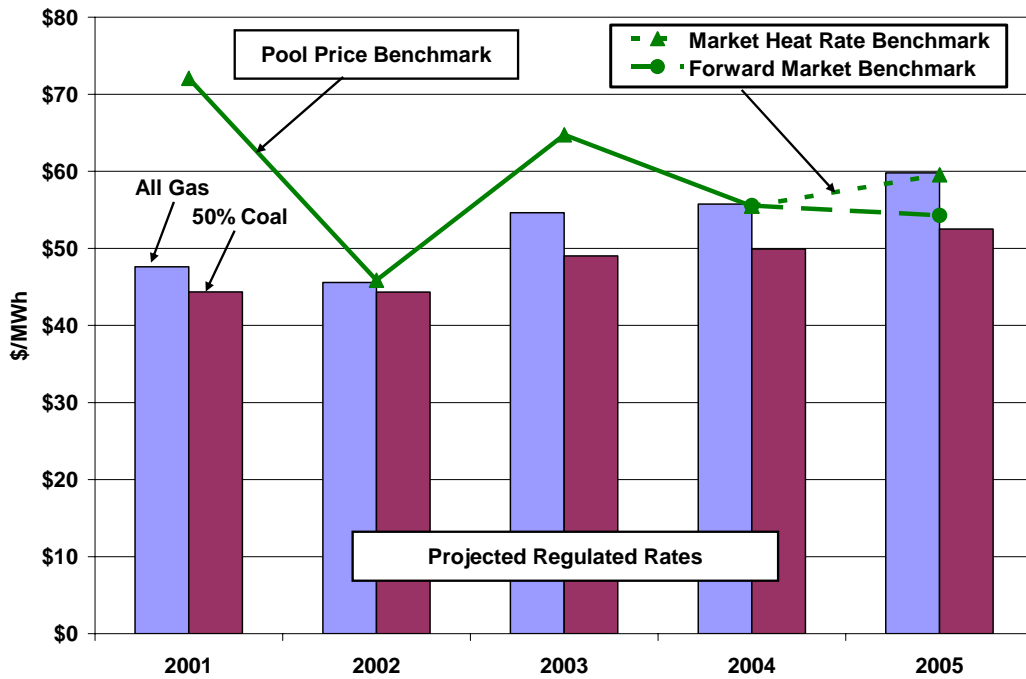


Figure 2. Rates under cont'd regulation vs. market benchmarks - (MSA new entry costs)



Customer impact of deregulation

In the 2003 report, we presented a summary of the quantifiable cost impact on customers stemming from deregulation. These are calculated as the difference between wholesale market prices and the rates under continued regulation, offset by the proceeds from the August 2000 PPA Auction and MAP process. The impact will also be affected by the value of the Hydro PPA held by the Balancing Pool, and the value of the Sheerness, Genesee and Clover Bar PPAs, also held by the Balancing Pool.

The impact due to the difference between wholesale market prices and rates under continued regulation is estimated by taking the difference, on a \$/MWh basis, and applying it to total customer load in each year. Under the current analysis, the customer impact of paying market prices rather than regulated rates over the period 2001-2005 is approximately \$1.6-\$3.9 billion. This is largely offset by approximately \$2.0 billion in refunds from the PPA Auction, however.

Under the central “All Gas” case, the net customer impact ranges from a benefit of \$450 million to a cost of \$540 million. Under the less likely “50% Coal” case, the net customer impact is a cost of \$0.9 - \$1.9 billion. Compared to total energy costs of approximately \$17 billion over the same period, the customer impacts is from +2.6% to -3.2% under the “All Gas” scenarios, and from -5.3% to -11.2% under the “50% Coal” scenarios.

As we noted in the 2003 report, the ultimate impact on customers will also be affected by the value of the Hydro PPA and the three thermal PPAs that did not sell in the 2000 Auction: Sheerness, Genesee, and Clover Bar. These four PPAs are held by the Balancing Pool on behalf of customers, and represent both assets (in terms of the electricity received under the contracts) and liabilities (in terms of the payments due under the contracts). The Balancing Pool currently values the Hydro PPA at \$689 million.⁸ The thermal PPAs are recorded as assets worth \$977 million; but also as liabilities of \$1.79 billion.⁹ The asset value, however, is based on the historic cost of the assets minus a write-down estimated in late 2000, while the liability is simply the sum of future (undiscounted) payment obligations under the PPA. Unlike the Hydro PPA, the valuation of the thermal PPAs does not represent an estimate of the ‘fair market value’ of the assets.

Only time – or the sale of these PPAs – will tell what the net value of these contracts is.

⁸ Balancing Pool, *Annual Report 2003*. Pg. 12. <http://www.balancingpool.ca/annual/03annual.pdf>

⁹ Balancing Pool, *Annual Report 2003*. Pg.. 25-26.

Conclusions

In our 2003 report, we projected that, by 2005, Alberta's competitive wholesale market prices would be lower than where regulated rates would have been under the "All Gas" case. In the present update to that report, we find that this conclusion holds even under the increased natural gas prices seen today. In fact, rates under continued regulation in the "All Gas" scenario using the MSA's cost inputs are in excess of deregulated market prices as early as 2004.

Had Alberta continued to regulate electricity generation, and – in the face of then-recent experience as well as the prevailing practice of building gas-fired plants - committed to meeting new demand by building equal amounts of gas-fired and coal-fired new capacity (the "50% coal" scenario, in our analysis), our analysis shows the resulting regulated rates would have been lower than market prices have been, at least through 2005. Depending on the cost of this new coal-fired capacity, the difference between the regulated rates and wholesale market prices would not exceed \$10/MWh in 2005, with some scenarios showing a gap of less than \$2/MWh.

When coupled with the \$2 billion refunded to customers after the PPA Auction, the net impact results under the central "All Gas" scenario range from a benefit of \$450 million to a net cost of \$540 million. This means that, had similar capacity additions as have actually occurred been built under a regulated system, there would have been no net financial benefit to customers relative to what has actually occurred under competition. The financial cost of the market prices seen in 2001 and 2003 is offset by the refunds they have received, and from the imminent 'crossover' of market prices and our estimate of rates under continued regulation. Barring severe and protracted supply shortages, future market prices should remain below the rates under continued regulation, as the latter would continue to increase with additions to ratebase.

Under the less likely "50% Coal" scenarios the impact is a net cost of between \$0.9 – 1.9 billion. Actually achieving such an outcome, however, requires several assumptions to be made regarding the foresight of the central planning decisions made under regulation. The experience with significant stranded cost in other markets – notably Ontario – clearly indicates that such central planning decisions often miss the mark.

Since deregulation, over 3,000 MW of new capacity has been built, with additional projects under construction or in development. This new capacity has been built at the risk of its investors – consumers will not serve as guarantors of this investment. Competition also continues to drive operational improvements, as demonstrated by declining market heat rates. Moreover, the presence of a robust marketplace for electricity has also enabled the development of substantial renewable generation capacity.

A remarkable transformation has been achieved within a relatively short period of time. As this and previous analyses show, Alberta's customers would not have been better off under continued regulation, and indeed are poised to reap the benefits of lower prices as early as 2004 or 2005.