www.albertaMSA.ca

MSA REPORT

Zero Dollar Offers

29 April, 2003

MARKET SURVEILLANCE ADMINISTRATOR

1 INTRODUCTION

The issue of \$0/MWh offers was brought to the attention of the MSA by several market participants on an informal basis. These participants had noticed that the volume of energy being offered into the real-time energy market (market) at a price of \$0/MWh (zero offer) had been steadily increasing since full deregulation of the Alberta electricity market in January 2001. The common fear of participants was that these zero offers were depressing Pool prices for all market participants. Participants' fears were realized during two hours in the early morning of June 30 2002 when the Pool price reached an all-time low of \$0.01/MWh. This event in particular served as a catalyst for this assessment report.

There are many reasons why generators might offer their energy into the market at a \$0/MWh price. In all cases, it is not the intent of the generator to actually receive a price of \$0/MWh for the energy sold. More often than not, zero offers are a means by which generators can ensure that their units will remain in merit and not be dispatched down. In some cases this is an operational requirement for the unit, and in other cases generators opt to offer \$0/MWh for market or regulatory reasons.

The MSA has undertaken a study of zero offer behaviour in the Alberta electricity market for the 2001 – 2002 period with the intent of determining if this behaviour has significantly impacted the fair, efficient and openly competitive operation of the market. The results are presented herein. Section 2 discusses the one-cent Pool price event and the events leading up to its occurrence. Section 3 explains the design of the Alberta energy market. Section 4 discusses supply and demand in Alberta. Section 5 presents the history and growth of zero offers. A summary of some of the reasons for offering capacity at \$0/MWh is included as Section 6. Section 7 attempts to determine whether zero offer behaviour has had a significant effect on the market. The report concludes with a discussion of future work and next steps in Section 8.

2 JUNE 30TH 2002 – POOL PRICE CLEARS AT ONE-CENT

During the early morning hours on Sunday June 30, 2002 the Pool price reached an all-time low of \$0.01/MWh. It occurred for two hours – from 4 am to 5 am (HE 05) and from 6 am to 7 am (HE 07). To many market observers, this was a significant event and possibly the start of a period of seriously depressed Pool prices. Analysis of the circumstances leading to the penny prices revealed the following:

- Demand during these hours was extremely low (6011 MW and 5907 MW – average demand for 2002 was 6784 MW). This was very early Sunday morning on the July 1st holiday weekend.
- Imports of 120 MW and 66 MW were occurring in these hours when normally one would have expected significant exports. This was driven

in part by the availability of energy from the Mid-C market for almost \$0/MWh due to very high hydro availability in the Pacific Northwest.

- Gas prices were extremely low on both June 29th (\$0.384/GJ) and June 30th (\$1.5098/GJ), significantly decreasing the operating cost of gas units therefore decreasing the typical offer prices of the gas units.
- All the coal units were running at full capacity with the exception of Sundance Unit 1. No other notable outages or derates were occurring during these hours.
- Some peaking units that are not usually incented to be available to generate during the off-peak hours (particularly on the weekend) were offering their minimum stable generation at \$0/MWh in anticipation of the bulk of their capacity being dispatched in on-peak hours at a higher price.

The combination of these events created the "perfect storm" for the market and resulted in the two \$0.01/MWh hourly spot prices. Had any of these circumstances changed, the price would have been higher. Note that only a few days prior to this event (June 25), prices climbed to the other end of the spectrum and for a duration of three hours the electricity clearing price was \$999/MWh – the maximum allowable offer in the Alberta energy market.

While such ultra-low prices are naturally of interest to the MSA, they are only a concern if they are symptomatic of inappropriate behaviour or poor market outcomes driven by poor collective behaviour. Other markets, such as New England, tolerate negative clearing prices on occasion without undue consternation.

It must be borne in mind that Pool price does not reflect the average price of electricity traded for a given hour, only the portion cleared at the spot price.

3 THE ALBERTA ENERGY MARKET DESIGN

There are a number of electricity markets in Alberta over which electricity is traded. This study focuses on the real time energy market.

The Alberta energy market operates in real-time based on the actual supply and demand in the province. Suppliers offer blocks of energy into the market at the price for which they are willing to sell it. Conversely, load may bid in its demand at the price it is willing to pay for the required energy. The combination of suppliers offers and customers load bids are combined into the merit order – a stacking of offers and bids from lowest cost to highest cost.

It is the job of the System Controller to dispatch energy based on the merit order. Lower priced energy is dispatched first and the System Controller works up the stack to the point where the supply and demand curves meet. The highest price block in-merit is the marginal block as it sets the system marginal price (SMP). SMP can change on a minute-by-minute basis depending on supply and demand.

At the end of each hour, the minute-by-minute SMPs are time weighted and averaged to calculate the hourly Pool price. This is the price that each generator is paid per MW they generated during that hour and the price that each customer buying out of the Pool is required to pay for the energy received.

The process of offering energy into the market is relatively simple. Each unit is allotted seven price ($/MWh)-quantity (MW) pair blocks per hour. Each block can be any size from 0 MW up to the capacity of the unit (so long as the sum of the seven quantities does not exceed the capacity of the unit). A generator can offer each of his blocks at any price he likes within the range of $0/MWh to $999.99/MWh.

Generators make their offers up to seven days ahead of the scheduled day of delivery. They have up to noon the day ahead of delivery to finalize their offers for any given day. After the noon-day-ahead cut-off, price-quantity pairs can only be changed through two mechanisms: energy restatements and locking restatements. A generator may, at any time during the day of delivery, use an energy restatement to restate the amount of energy he has available to the market. He cannot change the dollar value he is asking for this available energy, only the quantity of energy available. Generators also have the use of one locking restatement per day. When a participant uses his locking restatement he can submit a whole new set of seven price-quantity pairs. The use of locking restatements is prohibited within the T-30 (hour of delivery minus 30 minutes) window unless it is required for operational reasons.

Generators often offer the bulk of their energy into the market at variable cost; however, as the Alberta energy market is not a cost-based market, they have no obligation to do so. It is competition that constrains participants and imposes market discipline. Similarly, there is no rule preventing generators from offering some or all of their energy into the market at $0/MWh. All generation that wants to participate in the market <u>must</u> be offered into the merit order as required by the *Electric Utilities Act*.

Unlike supply, there is no requirement for load to bid into the merit order. The System Controller must ensure that all load is met whether it is bid in or not. Un-bid load is treated as a price-taker and must pay the hourly pool price for the energy consumed during that hour.

Importers and exporters are treated somewhat differently than domestic generation and load. Pool rules dictate that imports must offer their energy into the market at a price of $0/MWh and exporters must bid their demand at a price of $999.99/MWh. As such, importers and exporters must act as price-takers and pay or receive the hourly Pool price.

4 THE NATURE OF SUPPLY AND DEMAND IN ALBERTA

In Alberta, both the supply and demand of electricity are dynamic and follow cycles that are dependent on a variety of factors.

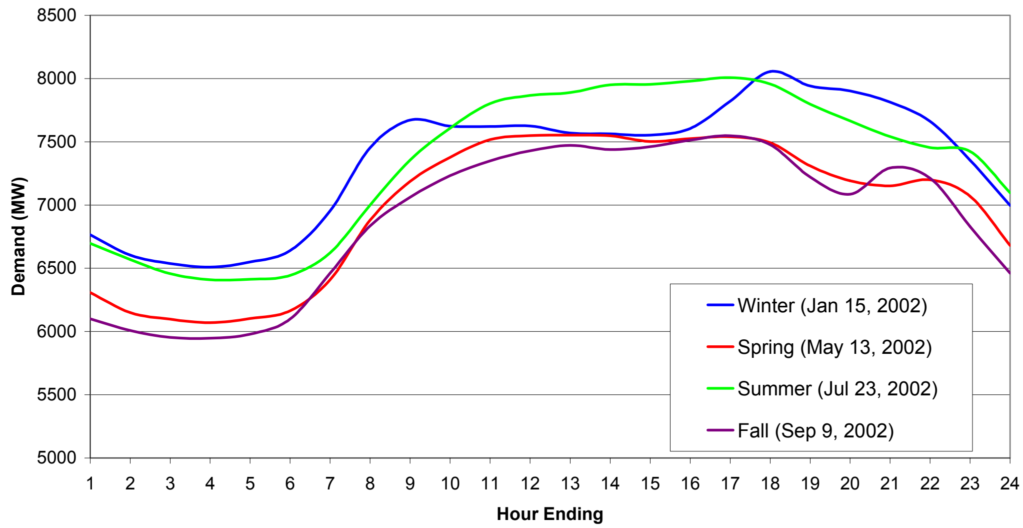
Demand

Alberta has a high industrial demand for electricity that is relatively constant over the year. The industrial demand accounts for approximately 60% of total Alberta demand. The main contributors to the fluctuations of demand over the year are residential and small commercial customers. Note that demand is relatively inelastic in Alberta. Very little is actually bid into the market, but estimates of around 300 MW of price-responsive demand have been made by the AESO's Operations group.

Changes in demand tend to follow the lifestyle of the typical Alberta population. Demand is higher when we are awake and lower when we are sleeping. It also experiences "rush hours" in the morning as we are waking up and getting ready for the day ahead, and, to a lesser extent, in the early evening as we go home, have supper and perform our evening activities. Demand also follows a weekly cycle and tends to be higher on weekdays when the majority of us are at work and lower on the weekends – particularly on Sundays when more businesses are closed. Lastly, demand follows an annual cycle. It is highest in the winter when the weather is cold, slightly less in the summer when the weather is hot and air-conditioning systems are running, and lowest in the spring and fall when the climate is more moderate. Periods of high demand are generally referred to as on-peak hours. In Alberta, on-peak hours are defined as 7 am through 11 pm, (HE 08 – HE 23) Monday through Saturday. All other hours (including all day Sunday and public holidays) are off-peak.

Figure 1 shows the typical weekday demand pattern for each season. It can be seen that demand is lower in the spring and fall than in the summer and winter. Also note that during the winter, there are two distinct demand peaks: one occurring in the morning rush hour and one occurring in the evening rush hour. The figure clearly shows the morning ramp up occurring during approximately HE 05 through approximately HE 11. During this period, demand increases by as much as 1,500 MW, depending on the season. The evening ramp-up is less pronounced and is most evident during the winter. During the three-hour period from about HE 16 through HE 19, demand can increase by as much as 500 MW. The daily ramp down covers the eight to ten hour period from the end of the evening ramp up (peak) to the start of the morning ramp up (trough). During this period, demand decreases up to 1,500 MW

Figure 1 - Daily Demand Cycles



Exports are a contributor to the Alberta demand, but their behaviour is somewhat different from domestic demand. The majority of exports typically occur overnight when the domestic demand is the lowest. In this way, exporters are able to take advantage of lower Pool prices during off-peak hours.

Supply

While demand is primarily dependent on small-scale factors (daily/weekly), supply is more seasonally variable. In Alberta, the three major types of generation classified by fuel source are hydro, coal, and gas (including co-generation).

Hydro generation is the most cyclical as the amount of electricity that can be generated is dependent on the supply of water in the reservoirs behind the dams. Water supply is highly dependent on climactic conditions including rainfall and snowmelt. Therefore, output from hydroelectric facilities tends to be greatest in the springtime when snowmelt is high, rainfall is quite high and the volume of water stored in the reservoirs is the greatest. Conversely, in a very dry summer, hydro output would be much lower. Hydroelectric generation also tends to be less in the winter when stream flows are lowest and the reservoirs are drawn down.

Coal generation can also vary seasonally, particularly if cooling ponds are a part of the process. During the warm summer months the effectiveness of the cooling pond is decreased (due to increased cooling water temperatures), decreasing the efficiency of the coal plant and not allowing the plant to operate at its full capacity.

The output from gas-fired combustion turbines is also dependent on the ambient air temperature. It will be higher in the winter when temperatures are lower and the opposite is true in the warm summer months.

Co-generation plants account for approximately 65% of the gas-fuelled generation in Alberta. In the past, the gas units in the system were mostly peaking units that operated primarily during on-peak hours when the demand is greatest. These new co-generation units are more often considered as part of base-load generation. The process associated with each plant typically requires long, uninterrupted periods of heat or steam generation – the operation of the electrical plant is fully entwined with the needs of the primary process and the decision to generate is usually not based on prevailing electricity prices. Some plants have the option of generating in response to market price for a portion of their output.

Supply of electricity in Alberta is also affected by full outages or partial outages (called derates) of units. To a certain extent, outages are coordinated through the System Controller and the Transmission Administrator of Alberta (TA). Generators with capacities above 40 MW are required to submit their outage plan (including planned and maintenance outages) for the next calendar year to the System Controller and the TA by October 31. Both the System Controller and the TA compile the outage schedules and publish an aggregated graph of the expected outages on their respective websites. The outage schedule is updated regularly to reflect the most up to date information. Note that individual generators may opt to move their scheduled maintenance based on the published outage schedule; however, neither the System Controller nor the TA can require a generator to re-schedule his planned maintenance. One exception to this is if a particular units' planned outage poses a threat to system security. In such cases, the System Controller will work with the generator to find a more suitable outage time.

Supply is also affected by the operational characteristics of the individual units. For example, coal units typically have long ramp times meaning supply from these units cannot be instantaneously available. Ramp up and ramp down times for gas units vary depending on the type of generator, while hydro units have virtually non-existent ramp up and down times and are essentially ready to run on a moments notice (provided there is adequate water supply). Other operational constraints may include minimum operating levels, minimum down and up times and start up times and costs.

Imports constitute a sizeable portion of system supply. Importers generally offer energy into the market during on-peak hours when the price they will be paid is higher. Imports tend to decrease in the overnight period. Unlike domestic supply, imports are scheduled hourly and are unable to respond to intra-hour dispatch. Note that the volume of imports coming into the province depends on the electricity prices in the neighboring markets, including the US.

The composition of the Alberta supply stack has changed in recent years. A summary of new generation over 2001 and 2002 is included as **Table 1**.

Table 1 – Summary of New Generation (2001-2002)

Unit	Capacity (MW)	Type	Date Commissioned
Cavalier (PC01)	104	Gas	July 2001
Balzac (NX01)	97	Gas	October 2001
Carseland (TC01)	81	Co-Gen (Gas)	July 2001
Redwater (TC02)	42	Co-Gen (Gas)	October 2001
Valleyview (VVW1)	46	Gas	December 2001
Rainbow 5 (RB5)	46	Gas	December 2001
Sundance 6 – expansion (SD6)	42	Coal	October 2001
Total 2001	**458**		
Mahkeses (IOR1)	180	Co-Gen (Gas)	November 2002
Cavalier - expansion (PC01)	25	Gas	December 2002
Bear Creek (BRCK)	50	Co-Gen (Gas)	November 2002
Total 2002	**255**		
TOTAL	**713**		

Of the new generation added in the 2001 – 2002 period, 45% was gas, 50% was co-gen, and 5% was coal. Assuming that the majority (but not all) of the co-gen capacity could be considered to cover base load, the new generation should theoretically increase available base load generation and peaking capacity in approximately equal proportions. The generation additions over 2001 were supplemented by the return to service of the 265 MW Wabamun Unit 4 in midyear. Conversely, the 139 MW Wabamun Unit 3 was decommissioned late in 2002, decreasing the overall capacity addition of 2002 from 255 MW to 116 MW.

In an effort to encourage new generation to locate in areas in which transmission is constrained, the TA instituted an Invitation to Bid on Location-Based Credits (IBOC) program. Under the auspices of this program, qualified generators receive Monthly Location Based Credit (LBC) Payments if their total generation for the month is greater than an agreed-upon threshold. IBOC units include the TransCanada co-gen unit at Carseland, the EnCana Cavalier gas unit, and the Nexen Balzac gas unit with a total capacity of 282 MW. Subsequent to the IBOC program, the TA introduced the Location-Based Credit Standing Offer (LBCSO) program. Monthly LBC Payments (calculated in the same fashion as IBOC LBC payments) are also awarded under this program, but qualified units also receive additional Annual Minimum Payments (based on total number of hours generating in the year) and Monthly Supplemental Payments (to cover periods of time when Pool price is lower than the assumed variable cost of running the units). The only LBCSO unit in service by the end of 2002 was the 50 MW TransCanada Bear Creek co-gen unit.[1]

Supply/Demand Relationship

As previously mentioned, the interaction of supply and demand through the merit order is the mechanism through which Pool price is determined. The following section discussed the supply/demand relationship in Alberta.

Run-of-river hydro and coal units are generally stacked at the bottom of the merit order and are referred to as base-load generation. These units are relatively inexpensive to run. It is therefore economically viable for these units to offer at least some of their seven available energy blocks at a low price. Because these units are at the bottom of the stack, they are rarely dispatched off. Due to the operational characteristics of the coal units, frequent starts and stops are quite costly and the units take a long time to ramp up and ramp down. Offering their generation at a low price decreases the risk of being dispatched up and down. Note that although most hydro and coal capacity is typically stacked at the bottom of the merit order, it is not obligated to be. Both coal and hydro units will often offer one or more energy blocks at higher prices.

Co-generation (co-gen) units are also often included as base load generation as the primary function of these facilities is another process and the cost of generating electricity is considered to be a part of the cost of the primary process. Some co-gen units tend to offer their full capacity at low prices while others only offer a portion of their capacity at low prices and the remainder of their capacity is scattered higher in the merit order. Gas units are generally more expensive to run and therefore tend to sit higher in the merit order. The cost of running a gas unit is highly dependent on the heat rate of the unit and the cost of natural gas. The Alberta market is not cost-based and generators may offer their energy at whatever price they like from a minimum of $0/MWh up to a maximum of $999.99/MWh. What provides discipline particularly to the supply side of the market is the power of competition - the risk of pricing their energy above the market and not being dispatched.

In Alberta, if all generation is fully available, the run-of-river hydro, coal and co-gen units usually generate enough electricity to cover the base-load – the typical demand during off-peak hours. Gas units are most often dispatched on during on-peak hours and are therefore often referred to as peaking units or peakers. Some peakers are more responsive than others and are able to ramp up and down in a few minutes. Others have much longer ramp times and are not as proficient at following demand. In addition, some units are unable to ramp up unless they are already running at a minimum operating level. These units provide energy into

[1] Note that early in 2003 the Calpine gas unit was commissioned. 125 MW or this project is classified as LBCSO capacity.

the market at a net loss in some hours in hopes of being dispatched to cover peak requirements at future, higher paying times. Clover Bar is a good example of this type of plant.

In summary, electricity demand in Alberta is cyclical in nature. Demand is generally higher during the day and lower at night and peaks during the morning and evening weekday rush hours. This leads to the definition of on-peak and off-peak hours. Demand is also generally higher in the winter and summer and lower in the spring and fall. The Alberta supply stack primarily consists of hydro, coal and gas (including co-gen) fuelled generation. Supply follows demand as required with some seasonal constraints on generation. Other factors such as outages, derates and operational characteristics also contribute to supply constraints. The supply demand relationship results in the merit order; the stacking of offers and bids in order of increasing price. Lower cost units (usually coal and run-of-river hydro) typically fill the bottom of the stack and meet the requirements of the base load. Higher cost units (usually gas) are typically stacked higher and tend to meet load requirements during on-peak hours, resulting in higher prices during these times. This is the typical merit order configuration, but generators (with the exception of importers) select their own offer prices. In doing so, they will assess the status of the competing generators, fuel costs, general market conditions and the risks of not being dispatched if the price is too high relative to the competition.

5 GROWTH OF MW OFFERED AT $0/MWH

Since January 2001, the amount of energy offered into the market at a price of $0/MWh has increased dramatically. **Figure 2** shows a time series plot of the 10-day rolling average[2] volume of total zero offers from January 2001 to December 2002. On-peak and off-peak zero offers are also depicted in Figure 2. Note that in general, more zero offers occur in the off-peak hours when the competition to be in merit is higher than in the on-peak hours.

At the start of 2001, the only units offering their energy at $0/MWh were a number of gas units offering their minimum stable capacity and some co-gen units that required their plants to be generating to sustain their primary process. Notably, none of the coal units were offering in energy at $0/MWh at this time.

Table 1 (see Section 4) summarizes the new generation that came on-line in 2001 and 2002. The table shows 42 MW of coal additions, 318 MW of gas additions, and 353 MW of co-gen additions, for a total of 713 MW of new generation over the two year period. The annual peak demand and energy over the past few years are presented in **Table 2.**

[2] The purpose of plotting 10-day rolling average data is to reduce the noise level (spikiness) seen in either daily or hourly data. The 10-day rolling average data clearly shows the upward trend of zero offers.

Figure 2 – Total 10-day Rolling Average Zero Offers

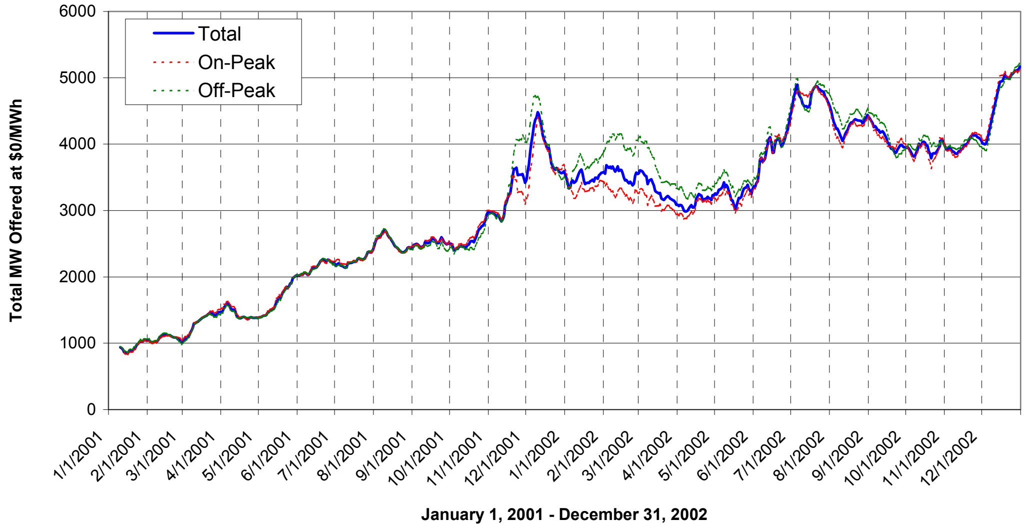


Table 2 – Growth of Capacity and Energy Requirements

Year	2000	2001	2002
Peak Demand (MW)	8185*	8334*	8570
Growth (%)		1.8	2.8
Energy Traded (1000 GWh)	54.4	54.7	54.3
Growth (%)		0.7	-0.7

* Recorded values are adjusted by 400 MW to account for a change in the Pool's format of reporting of demand

Over the course of 2001, more capacity was added to the system than was required to meet the growing demand and thus the competition to remain in merit increased. This was particularly true in the off-peak/overnight hours when demand is at its lowest. It became necessary for the large coal units to offer their minimum stable generation level at $0/MWh to ensure not being dispatched off. Note that although this new generation was creating a supply surplus, the surplus is not as large as may be expected. A significant portion of the new generation was co-gen. Typically, such a development also includes some new load that accounts for a portion of the supply, resulting in a reduced net to grid value of energy. That being said, the overall impact of the increased capacity was to increase competition, incenting more units to offer their energy into the market at lower costs in order to remain in merit.

Moving into 2002, even more units came on-line and the trend of increasing $0/MWh offers continued. Although peak demand was higher in 2002 than in the two years previous, total energy traded for the year was lower. This has the effect of further increasing competition.

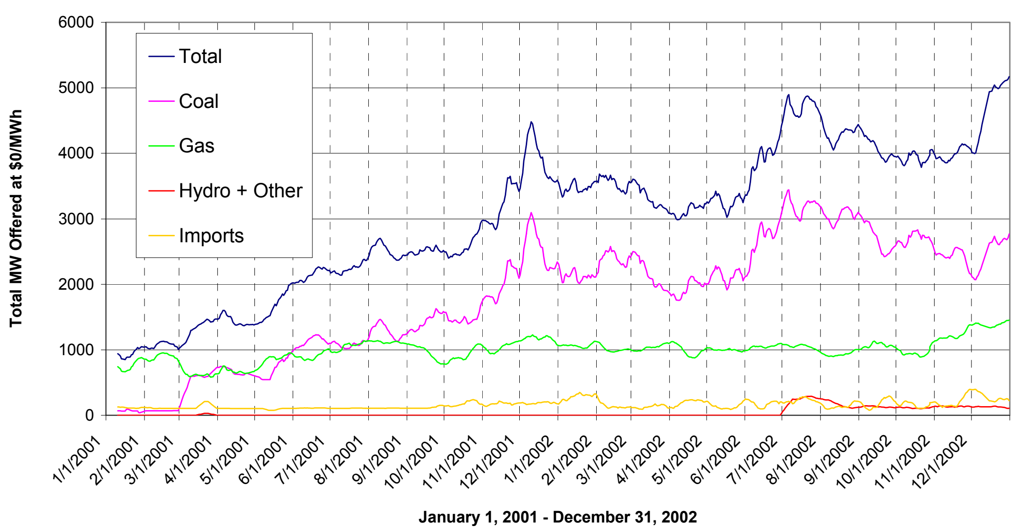
As might be expected, the lower-cost coal units were the first to change their offer strategies and start offering significant blocks of energy at $0/MWh. This began to occur in early March 2001. The number of coal unit zero offers has increased dramatically over the past two years. In January 2001 an average of approximately 65 MW of coal generation were offered at $0/MWh. By the end of December 2002 an average of close to 2,500 MW were typically being offered at $0/MWh. One might argue that the coal units should have offered their minimum stable generation levels of capacity at $0/MWh throughout. Clearly, the system balance of supply and demand in early 2001 was such that the generators did not feel the need to do so.

The change in $0/MWh offers for other types of units has been less dramatic. Gas unit zero offers have increased from about 760 MW in January 2001 to about 1,400 MW in December 2002. In January 2001, almost no hydro generation was being offered at $0/MWh. By December 2002 an average of approximately 130 MW of hydro generation were being zero offered.

Zero offer behavior of imports has also changed during the period. However, this is largely due to a change in the Pool Rules. During 2001, importers were treated like any other generator and allowed to offer their energy into the market at whatever offer price they liked. Near the end of December 2001 a new rule was introduced and importers are now required to be price-takers and offer their energy into the market at $0/MWh. This rule change obviously changed the offer patterns of importers, but not as dramatically as may be expected. In actuality, some importers began offering energy at $0/MWh somewhat earlier than dictated by the rule change. Importers may have elected to zero offer for many of the same reasons as other generators.

Figure 3 depicts the 10-day rolling average volume of zero offers for 2001 and 2002 broken down by generation type. Note that the increase in total zero offers is most strongly correlated to the increase in zero offers of the coal units.

Figure 3 – 10-day Rolling Average Zero Offers by Type



While the above figure illustrates the progression of the growth of zero offers quite well, it is somewhat deceiving to compare zero offers from different unit types on the same scale. At the end of 2002, coal-fired plants accounted for approximately 50% of the total generation capacity within the province, while gas (including co-gen) and hydro (and other) units accounted for 40% and 10% respectively. As such it may be useful to examine zero offers as a percentage of total capacity by generation type. This is illustrated in **Table 3**. The analysis includes an approximation of average on-peak imports (when most imports occur). Values for other generation types are for all hours. Note that the 2002 total MCR value incorporates new generation added to the system in the 2001-2002 period.

Table 3 – Zero Offers a Portion of Total Capacity

Generation Type	January 2001 $0/MWh			December 2002 $0/MWh			Change in % of Total
	Total MCR	MW	% of Total	Total MCR	MW	% of Total	
Coal	5,620	65	1%	5,660	2,500	44%	43%
Gas/Co-gen	3,810	760	20%	4,480	1,400	31%	11%
Hydro + Other	1,090	0	0%	1,090	130	12%	12%
On-Peak Imports	953	88	9%	953	325	34%	25%
TOTAL	**11,473**	**913**	**8%**	**12,183**	**4,355**	**36%**	**28%**

The above analysis shows that the percent of total capacity being offered at $0/MWh has increased by 28% from January 2001 to December 2002. While all generation types have increased their zero offers, by far the most dramatic increase is in the coal generation category where zero offers have increased from 1% to 43% over two years. (It is interesting to note that the volume of coal generation offered at $0/MWh in December 2002 is roughly the same as the total minimum stable generation for all of the coal plants.)

The gas/co-gen values in Table 3 include all zero offers made by the Clover Bar units. For all of 2001 and most of 2002, Clover Bar was operated by the Balancing Pool. Due to operational constraints of the Clover Bar units, the mandated offer strategy required that the minimum stable generation of each unit be offered at $0/MWh. If all four Clover Bar units were running, this would account for 80 MW offered at $0/MWh.

While zero offers of imports have obviously increased due to the rule change, note that in January 2001 approximately 9% of full import capacity (full tie-line capacity) was already offering into the market at $0/MWh[3]. Not unlike domestic

[3] Due to constraints in the tie-lines, full tie-line capacity is rarely available. In January 2001, imports offered at $0/MWh accounted for approximately 81% of imports that actually flowed across the tie-lines.

generators in 2001, importers might have zero offered their energy to ensure their energy was scheduled (in merit).

6 REASONS FOR OFFERING CAPACITY AT $0/MWH

There are a wide variety of reasons why specific generating units may offer their full capacity or some portion of their capacity at $0/MWh. The majority of reasons can be split into two categories: operational reasons and market and regulatory reasons.

Operational Reasons

Operational reasons vary from unit to unit depending on the characteristics of the unit, but are generally quite similar for each unit type. Many of the operational reasons for zero offering are explained in the discussion on Supply included in Section 2. Operational reasons why electricity might be offered into the market at $0/MWh are summarized in **Table 4**.

Table 4 – Operational Reasons for Zero Offers

Unit Type	Reason for Zero Offer
Coal	• Do not want to dispatch down or off (to avoid long and expensive start-up process) • Minimum run constraints • Unit testing or commissioning • Minimum stable generation
Co-gen	• Do not want to interrupt heat or steam required for the primary process at the plant (electricity is a valuable by-product of some other process) • Minimum run constraints • Unit testing or commissioning • Minimum stable generation
Gas	• Minimum run constraints • In the case of Clover Bar and Rossdale, annual limits to numbers of starts specified in the PPAs • Unit testing or commissioning • Minimum stable generation
Hydro	• Reservoir storage full (must generate or spill) • Maintaining run of the river flows • Unit testing or commissioning

Market and Regulatory Reasons

Unlike operational reasons for zero offers, market reasons tend to be common to all generation types (coal, gas and hydro). Common reasons for offering $0/MWh into the energy market include:

- Imports Required to Offer $0/MWh
  As previously described, in late December 2001 the Power Pool introduced a new rule that forced importers to be price takers and offer their energy in to the market at a price of $0/MWh.

- Participation in the Ancillary Services Market
  Some units must be generating at a minimum value to position themselves to be able to participate in the Ancillary Services market. Generators are incented to offer this minimum generation at $0/MWh to ensure they will not be dispatched below this level.

- Qualification for IBOC and LBCSO Credits
  In an effort to incent new generation to locate in areas of high demand and low supply, the TA established the IBOC and programs. In these programs, qualified generators are rewarded with Monthly LBC Payments if they meet or exceed some agreed-upon output level over the period of a month. (Note that the IBOC and LBCSO programs vary in the LBCSO units are also awarded Annual Minimum Payments and Monthly Supplemental Payments in addition to Monthly LBC Payments.) In some cases, it is more profitable for generators to operate at a loss in the spot energy market in order to receive the TA credits. On such occasions, the generator may elect to offer at $0/MWh. It is suggested that the AESO review these programs to ensure that they are delivering the intended results.

- Energy Sold Forward
  Some market players have initiated forward contracts for the sale of energy. In these cases, the generators have pre-arranged the sale price of their electricity and are therefore not subject to Pool price. However, these contracts also commit the generator to provide the energy sold. Offering the energy at $0/MWh ensures that delivery of the sold energy is possible. This is not necessarily the optimum decision in all cases. If unconstrained, economic theory would have the generator bid at short-run variable cost on the basis that this would allow the seller the option of buying from the Pool instead of generating should Pool price be lower than his cost of generation. In this way, the more efficient outcome occurs whereby the load is met by the lower priced supply source. Market participants do not always follow the model suggested by economic theory.

- Strategic/Competitive Behaviour
  A zero dollar offer may be considered strategic or competitive if a generator offers their energy in to the market at a $0/MWh price in an effort to cause a change in other market participants' offers or to increase market share. For portfolio management, a generator may wish to lower overall Pool price to protect or cover a short position. The MSA closely monitors the market to

ensure that Pool prices are not manipulated in a significant or sustained manner.

- Fuel Contracts
  In some cases, generators have contracts in place that may be on a take-or-pay basis. Effectively, the variable cost is then reduced substantially and they may elect to offer at $0/MWh. Take-or-pay contracts are most commonly associated with coal generation. In these cases, the generator has arranged a long-term contract with the coal mine. In the case of the PPA units, the risk associated with such contracts may not pass through to the buyer. Take-or-pay contracts are less common for gas units.

- Price-Chasing Units
  Frequent visitors to the MSA's Web site will have read a letter in December 2002 describing certain offer behaviour by some generators in the market. Essentially, these generators offer their energy at $0/MWh and use energy restatements to control the actual amount of energy they bring to market. This then contributes to the volume of MW offered at $0/MWh. This practice of using energy restatements for market reasons is troubling to the MSA. If it continues, the MSA will request that the AESO considers limits to the use of energy restatement for market reasons similar to those for locking restatements.

Maximum Zero Offers

Taking all the above operational and market reasons for offering $0/MWh into the market into consideration, a theoretical set of zero offers can be determined. **Table 5** summarizes the maximum amount of energy that might be offered at $0/MWh for each generation type. Note that all values are estimated above and beyond the minimum stable generation number for each category. As such, the values can be added to determine a reasonable upper bound of MW offered at $0/MWh under a certain set of specific circumstances. Some reasons are not included in the table as $0/MWh offers falling into these categories are already included in other categories.

Table 5 – Maximum Zero Offers

Reason	Expected Volume of Zero Offers					
	Coal	**Co-Gen**	**Gas**	**Hydro + Other**	**Imports**	**TOTAL**
Minimum stable generation *	2,600	600	250	0	0	**3,450**
Above and Beyond Minimum Stable Generation						
Avoid dispatch down (all coal capacity)	3,260	0	0	0	0	**3,260**
Heat/steam generation	0	850	0	0	0	**850**
Full reservoir (100% of total Hydro – extreme case)	0	0	0	1090	0	**1090**
Unit testing	Negligible					
Import rule	0	0	0	0	953	**953**
IBOC/LBCSO	0	130	170	0	0	**300**
Forward contracts	Variable					
Strategic behaviour	Variable					
Price chasing	Variable					
TOTAL	**5,860**	**1,580**	**420**	**1,090**	**953**	**9,903**

Note: Capacity could also be offered at $0/MWh for reasons including coal contracts, run-of-river hydro flow, minimum run constraints, PPA restrictions on number of stops and starts, fuel contracts and provision of ancillary services. These items are not included in the table as capacity that might be associated with these reasons is already accounted for in other categories.

* From TA stacking order

The above analysis shows that close to 10,000 MW might be offered at $0/MWh. This represents just over 80% of the total generation available to the province (2002 domestic generation + imports) and approximately 3,000 MW more than average Alberta demand. In reality this would be a very unlikely scenario. Table 4 assumes a number of events occurring simultaneously, including:

- Full capacity available from all units and interties;
- All coal units offering their full capacity at $0/MWh;
- All co-gen units offering their full capacity at $0/MWh;
- Extremely high water levels forcing the hydro units into must-run and spill situations; and,
- All IBOC/LBCSO units scrambling to collect their TA credits.

Changing any one of these conditions would have a significant impact on the actual volume of zero offers.

Note that the 10,000 MW zero offer value is an estimate of a reasonable upper bound of zero offers. As the volume of zero offers observed to date is nowhere near this high, this estimate indicates that there is the potential that the trend of increasing zero offer behaviour may continue. However, if as much as 10,000 MW was offered into the market at a $0 price, the price signal would be eliminated which would lead to countless other market problems.

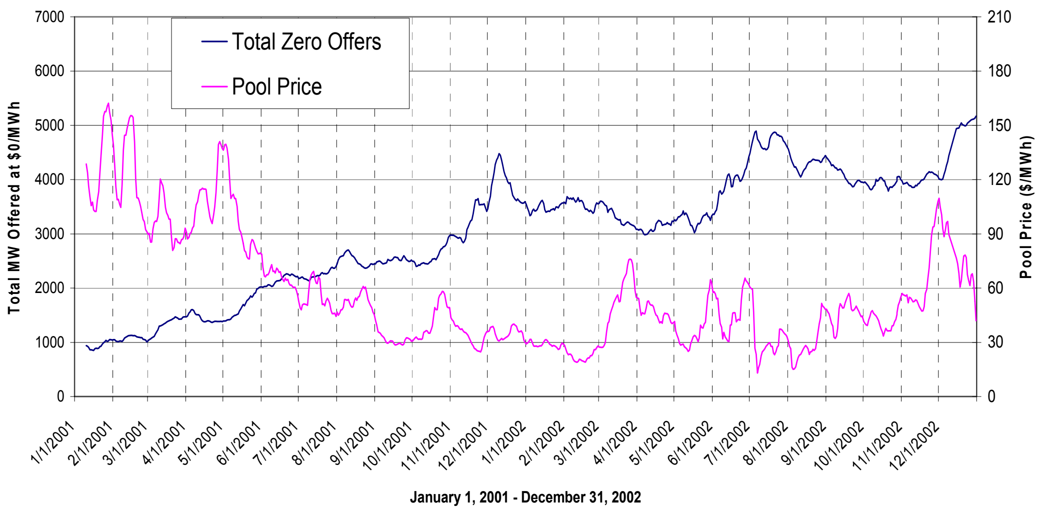
7 HAS THE CHANGE IN MW OFFERED AT $0/MWH HAD A SIGNIFICANT EFFECT ON THE MARKET?

It has been conclusively shown that the volume of zero offers has significantly increased over the 2001 – 2002 period. The question now is whether this change in offer strategies has had any significant impact on the operation of the market or the price paid for electricity in Alberta, and if the zero offer strategy is fair, efficient and openly competitive.

General Effects

Figure 4 illustrates the progression of 10-day rolling average zero offers and the 10-day rolling average Pool price. Over the period, the volume of zero offers has increased while there was a general downward trend in Pool price. By itself, the graph does not indicate any cause and effect relationship between the two. If zero offers were a significant factor affecting Pool price, a much higher correlation and correspondence of the peaks and valleys in Figure 4 would be observed. For example, at times of high zero offer spikes, you would expect a corresponding low spike in Pool price and vice-versa. There is no evidence of this behaviour, only that the volume of zero offers trended up while Pool price trended down.

Figure 4 – 10-day Rolling Average Zero Offers and Pool Price

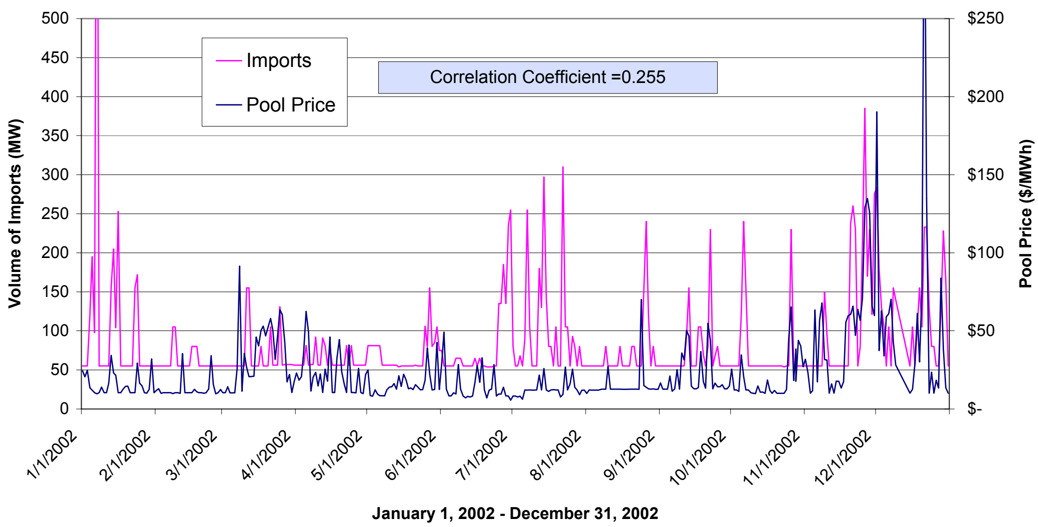


Imports

Since late 2001, a change in Pool rules has required importers to offer their energy into the market at $0/MWh. This has had the effect of increasing the total amount of zero offers observed. Some market participants believe that this rule change has assisted in "tanking" the Pool price.

Figure 5 shows the 2002 hourly Pool price and the 2002 hourly volume of imports ($0/MWh). These two variables are positively correlated with a correlation coefficient of 0.255 (statistically significant at the 1% level). The figure also shows that the correlation is stronger at some times and weaker at others, and is strongest from about mid-November to the end of December. Periods of weaker correlation do not appear to coincide with any particular price range or to be dictated by some threshold volume of imports. The positive correlation does indicate that importers continued to respond to positive Pool prices despite being obliged to be price takers in the Alberta market.

Figure 5 – 2002 Hourly Imports and Pool Price



Theoretical Price Effect

In order to determine the effect of zero offers on Pool price, a theoretical merit order was developed. This merit order is based on the assumed variable cost[4] of all domestic generation in the 2002 supply stack (imports are not included). Units are stacked in order of increasing variable cost. The theoretical merit order assumes that all units are fully available and there are no outages or derates. Note that in the theoretical merit order there are no zero offers as each unit incurs some cost to operate.

If zero offers are introduced, the merit order changes. The effect on Pool price, if any, is highly dependent on where within the stack the offers are removed and re-inserted at a price of $0/MWh. For example, moving low priced coal or run-of-river hydro units from their original offer position to a $0/MWh offer position would not affect the Pool price except in periods of low demand. However, moving higher priced gas-fired units to $0/MWh offers would have some impact

[4] Variable cost includes variable O&M costs, fuel costs (calculated based on 2002 average values), transmission costs and IBOC/LBCSO credits.

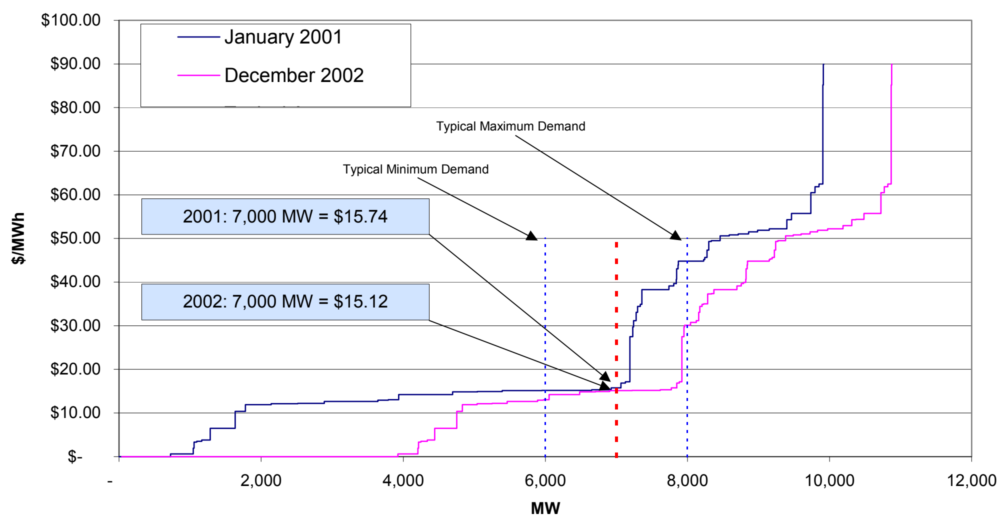
on Pool price if those units would have set price or had been out of merit. The effect on Pool price can be seen to be highly dependent on demand. There can only be an effect on Pool price if energy that would normally have been out-of-merit (above SMP) is offered at $0/MWh.

Analysis of the change in zero offer behaviour has shown that between January 2001 and December 2002 zero offers for coal, gas (including co-gen) and hydro (+other) units have increased on average from 1% to 44%, from 20% to 31% and from 0% to 12% of their respective market size. To try to simulate the occurrence and the price effect of the increasing zero offers, two new theoretical merit orders were generated: one for January 2001 and one for December 2002. The January 2001 merit order includes only units that were in service at the time. Zero offers were added as shown in **Table 6**. Zero offers were added uniformly for every unit of a given unit type. For example, if a 400 MW coal unit had a variable cost of $12.50, for the January 2001 case, 4 MW (1%) would be offered at $0/MWh and the remaining 396 MW (99%) would be offered at $12.50/MWh. The two merit order curves are shown in **Figure 6**. [5]

Table 6 – Addition of Zero Offers to the Theoretical Merit Order

Unit Type	January 2001		December 2002	
	$0/MWh Offers	Variable Cost Offers	$0/MWh Offers	Variable Cost Offers
Coal	1%	99%	44%	56%
Gas (incl. Co-gen)	20%	80%	31%	69%
Hydro (+other)	0%	100%	12%	88%

Figure 6 – Theoretical Merit Order Comparison



[5] Note that this theoretical merit order uses full unit capacities differs from the theoretical merit order referenced in the MSAs Assessment Report – Intertie Energy which uses capacities derated by 10%.

The theoretical merit order comparison shows that for a typical average demand in Alberta (7,000 MW), the Pool price in January 2001 would have been $15.74/MWh and the Pool price in December 2002 would have been $15.12/MWh. This is a decrease of $0.62/MWh. Considering the typical range of Pool prices, this is not a large difference. However, Alberta demand typically varies between about 6,000 MW and 8,000 MW. Theoretical differences in Pool price are potentially much larger when this wider band of load is examined. At 6,000 MW demand the difference is $2.16/MWh and is $14.72/MWh at 8,000 MW.

A similar analysis was conducted to illustrate the effect of importers being required to offer their energy at $0/MWh. Results of that analysis showed that the overall impact of import zero offers on Pool price has been negligible.[6]

Figure 6 also shows that increasing zero offers have had the effect of steepening the merit order curve (although the effect is somewhat masked as the total generation in the 2001 and 2002 cases is not the same). A steeper merit order curve will result in higher Pool price volatility if the range of demand to be met covers the area of the supply curve from low to high prices, as is the case in the Alberta market.

Figure 7 shows the weekly mean, standard, and coefficient of variation (standard deviation / mean) of Pool price. The coefficient of variation is a measure of the variability of a variable about the mean. A higher coefficient of variation indicates higher volatility, and a lower coefficient of variation indicates a lower volatility. Pool price started to be more volatile in about March 2002 and has continued to remain quite volatile. Particularly high Pool price volatility is noted in the summer of 2002 as well as in December 2002. The largest spike in the volatility curve (COV = 276%) occurs in a week at the end of June 2002 where prices cleared at both extremes of the price spectrum ($0.01/MWh and $999/MWh) in the same week. **Figure 8** shows average monthly zero offers and Pool price volatility. The correlation coefficient between Pool price and coefficient of variation is 0.66, which indicates a reasonable correlation. This further confirms the increase in Pool price volatility due to the volume of zero offers increasing over time.

[6] Refer to the MSA's *Assessment Report: Interchange Energy*.

Figure 7 – Pool Price Volatility

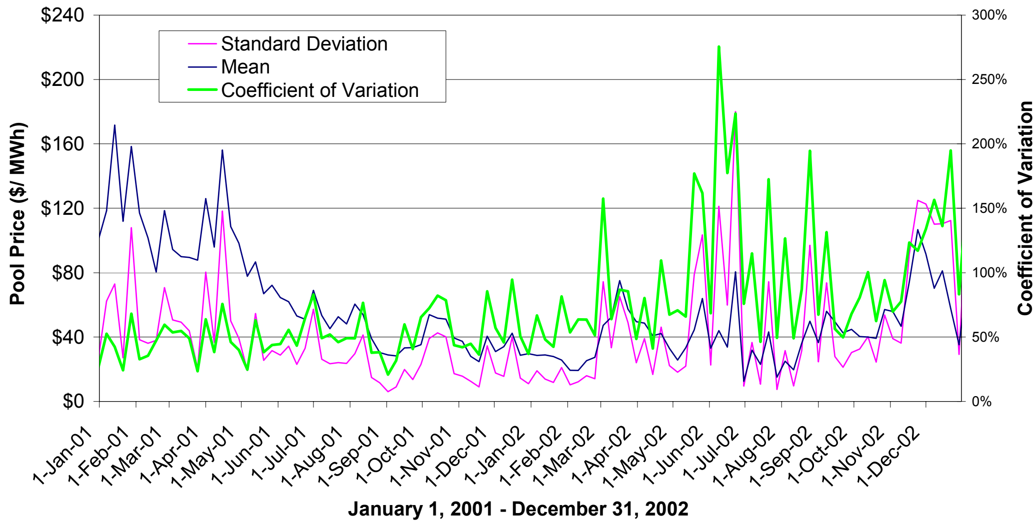
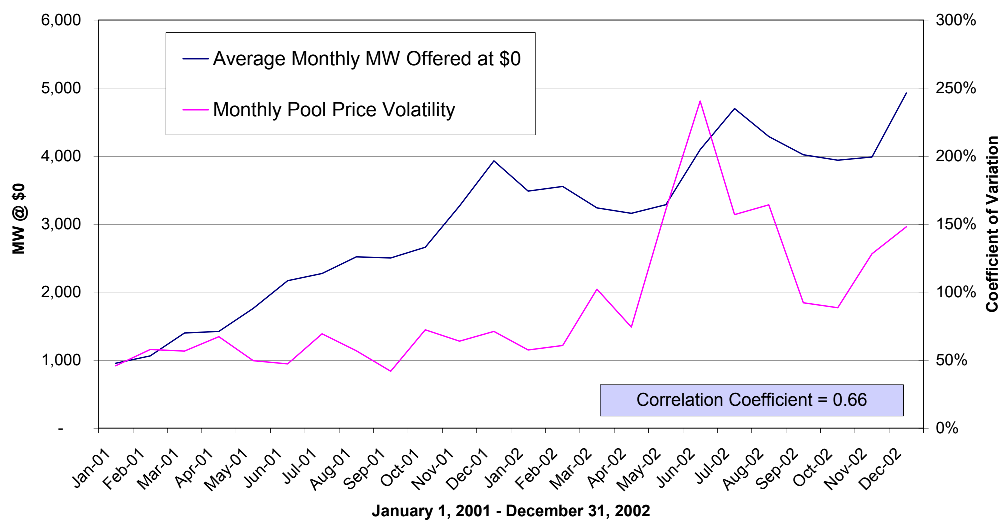


Figure 8 - Correlation of MW @ $0 and Pool Price Volatility



The MSA views an increase in Pool price volatility as a somewhat undesirable development in the market. It suggests that price discovery may be a problem for participants and that the market is operating in a less efficient manner than previously. This implied inefficiency results in greater risks to most market participants.

However, an increase in Pool price volatility could be a desired outcome for some participants – particularly those with diverse asset portfolios that include base load and peaking generators. Greater Pool price volatility could result in greater profits for those participants. The MSA has not found any participant who is purposefully attempting to induce price volatility through its ongoing monitoring efforts.

Assessment of Fair, Efficient and Openly Competitive Behaviour

As part of its mandate, the MSA has the role of ensuring that the Alberta electricity markets are operating in a fair, efficient and openly competitive manner to the benefit of both producers and consumers. The following section assesses the impact of observed zero offer behaviour on these three aspects of the market.

The question of whether or not zero dollar offers constitute fair, efficient and openly competitive behaviour is difficult to answer, as there are no absolute measures of these characteristics. The key is to look at past market performance and make a judgment on the *relative* operation of the market.

The fact that there are no specific rules or regulations inhibiting any one participant or any group of participants from offering its energy at $0/MWh makes it a fair practice. Although the logic behind offering $0/MWh varies for each supplier (and makes more sense for some than others), every participant has the option to zero offer.

Efficiency is a value proposition between stakeholders – producers and consumers. Two types of economic efficiency could be affected by zero offers: allocative efficiency and exchange efficiency. In this case, allocative efficiency could refer to the distribution of different types of units within the supply stack. When a higher cost unit (usually a gas fuelled unit) elects to offer its energy at $0/MWh rather than at its expected (usually variable) price, coal units who are offering their expected (usually variable) cost are displaced further up the merit order. If enough higher priced units start to adopt a zero offer strategy, it has the effect of lowering Pool price to one that would be expected to be set by a coal unit, but include a higher than expected amount of gas generation. This could lead to misleading price signals and result in less efficient market operation. Also, for a given level of demand, the *right* mix of fuels may not have been used on the supply side or reflected in the fuel prices.

One measure of exchange efficiency could be volatility. As the volatility of the market increases, the risk associated with participating in the market also increases. As the risk of participating in the market increases, participants will seek to mitigate the risk through increased hedging. However, the cost of hedging is directly linked to the volatility of the commodity being hedged. Zero offer behaviour has been shown to increase Pool price volatility and could therefore be considered a sign of market inefficiency.

An openly competitive market would be one in which there were few barriers to entry and there was sufficient market liquidity. Zero offer behaviour could be seen to be creating barriers to entry by depressing Pool prices and making the electricity market appear to be a difficult environment in which to make a profit. However, Pool prices are often low due to a number of factors and should be expected in normal market cycles. It is difficult to assess whether there has been any effect on barriers to entry over the limited time that the market has been in operation. As time progresses, a more complete picture of barriers to entry resulting from zero offers might evolve.

The relative number of active (those willing to set SMP) and passive (those trying to avoid setting SMP or those who are simply not interested in setting SMP) participants in the market could also be an indicator of openly competitive behaviour. A brief analysis has shown that the number of active participants[7] has not changed appreciably from 2001 to 2002. This infers that zero offer behaviour has not had a noticeable impact on market liquidity. In fact, the analysis shows that as time progresses, the list of active participants has changed, which might actually suggest a positive influence on market liquidity and competition in the market.

As the volume of zero offers increases, pressure on those generators who are willing to set price increases. These units may react to this pressure by offering their energy at higher prices than they would if less energy was offered at $0/MWh to compensate for the additional dispatch risk they are exposed to by others who are zero offering. In this way, zero offer behaviour could be viewed to be decreasing the level of competition in the market.

The shape and slope of the supply curve could be considered an indicator of market elasticity – a concept that might also be used to measure the competitiveness of the market. As the number of zero offers increases, the staircase shape usually associated with the supply curve starts to disappear and the supply curve starts to resemble a hockey stick (reverse "L" shape), indicating decreased market elasticity. This could be a sign that the competitiveness of the market is reduced.

The main price effect of increased volumes of zero offers has been shown to be increased volatility. Zero offer behaviour then has had a somewhat negative effect on the fair, efficient and openly competitive operation of the market. This is an indication that while the market still appears to be reasonably healthy, further increased zero offer behaviour could result in a more unfair, inefficient and less competitive market.

Outcome

Results of the foregoing analyses indicate that zero offer behaviour has in fact had some effect on the Alberta market. The analyses indicate that zero offer behaviour may have contributed to a slightly lower Pool price and has likely contributed to increased Pool price volatility. However, it is not clear that the effect on the market has been significant. The theoretical merit order curves show that for an average demand, price has changed only marginally.

It is important to note that the majority of observed zero offer behaviour appears to be happening for various reasons, such as those discussed in Section 4. As

[7] For the purposes of this analysis, active participants are defined as those participants offering energy into the market in the range of System Demand +/- 100 MW.

determined in that section, it is possible that as much as 80% of the total domestic capacity could be offered into the market at $0/MWh leading to a glut of zero prices – clearly not a desirable result.

Zero offers are not seen to be hindering the operation of a fair, efficient and openly competitive market. The increase in Pool price volatility could be seen to indicate a somewhat less efficient market, however, the nature of the market is such that various conditions will affect its operation. It is natural that Pool prices will rise and fall as a result of market conditions. It is possible that what at first seems like Pool price depression due to increased zero offers could in actuality be the normal operation of the market.

8 NEXT STEPS

This study has examined the evolution and effect of zero offers on the Alberta electricity market over the 2001-2002 period. It is likely that the observed zero offer behariour will continue in the future. The MSA will continue to monitor the situation and keep stakeholders appraised of any major disruptions to the fair, efficient and openly competitive operation of the market as a result of zero offer behaviour.

Keep in mind that events such as the occurrence of the $0.01/MWh Pool price in the summer of 2002 may well occur again. This is not an indication that there is an inherent problem with the operation and design of the market. However, persistence of extremely low (or high) prices is a warning that all is not well and efforts should be made to identify and change the factors causing the undesirable outcome.

In addition to the MSA's continuing work in this area, the AESO's Market Development group is studying this matter from the perspective of market design. The MSA fully endorses the AESO's undertakings and will provide assistance and support as required. It is the MSAs view that if the benefits of any changes to the market design outweigh the costs associated with the changes, then the change should be considered positive. The MSA asks the AESO to consider the following in order to reduce the amount of involuntary zero offers:

- **Locking Restatements.** Generators sometimes are forced to use their one locking restatement for the day to position their units to provide Ancillary Services. In some situations, a generator may need to then offer the required base capacity at $0/MWh for the balance of the day in case they are called into active duty from standby status. The AESO may wish to consider a rule change which would recognize that single locking restatements may not be the most appropriate tool for units to position for ancillary services.
- **IBOC/LBCSO Contracts.** It may be worthwhile to examine the performance of these contracts to assess how well they are delivering the intended results. Such a review might indicate a different incentive model for any future contracts.

- **Offer Structure.** Some of the so-called price-chasing units complain that their behaviour is 'forced' on them due to the nature of the Pool's offer structure. They feel that they are not sufficiently rewarded for using a start and providing much-needed peaking capability to the system. Perhaps some consideration to an offer structure that includes allowances for costs of start-ups or the development of incentives for non-zero offers could be given. The current market structure requires generators to roll all these factors into their unit energy offers. However, although the model works well for base load generators with few starts and stops (e.g., coal units) it works less well for peaking units that are operated each day on a very intermittent basis.

Allowing importers back into the merit order with non-zero offers would have the effect of decreasing overall zero offers, and would provide some much-needed 'shoulder' and liquidity into the merit order. Such a change would have to be weighed against all other considerations concerning tie lines in a detailed analysis. The MSA requests that government and the AESO review the policy with respect to the treatment of imports to determine if current practice remains the most appropriate.