Alberta Wholesale Market Price Cap Discussion Paper

June 23, 2009

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1.0 Introduction

Alberta's electricity market has had a price cap of $1000/MWh since its inception in 1996. During the first several years of operation, the system marginal price (SMP) did not reach the cap, but in recent years prices have reached the cap with increasing frequency. Some participants have suggested that this is evidence the price cap needs to be raised, and as a result, the AESO examined whether the price cap caused any interference to the functioning of the wholesale market.

The price cap study was initiated by the Market Advisory Committee (MAC), and a price cap sub-committee was formed. The sub-committee conducted a review of the issues that could possibly be created by the $1000/MWh price cap and presented the results to the MAC. The AESO appreciates the work done by the subcommittee and the valuable input received during the process. It should be noted, however, that the resulting report is an AESO product designed to engage industry in a consultation process and does not necessarily represent the views of the subcommittee. All market participants are invited to provide feedback on this report.

The report presents information on the market and impact of the price cap in a number of areas:

- Price cap policy background
- Frequency of the price cap events
- Importance of scarcity pricing for generator returns
- Generation investment in Alberta
- Examination of any issues created by the price cap in the fair, efficient and openly competitive (FEOC) wholesale energy market
    - Long Lead Time Energy (LLTE)
    - Intertie utilization
    - Demand Responsiveness
    - Impact on generator offers

Also included is a review of other energy only markets and the price caps in those markets.

This report is limited to data analysis and conclusions related to any issues caused by the current price cap. Questions around what might happen if the cap was changed are not directly addressed in this paper, but the other market review provides some insight based on experience in other markets.

As a result of the analysis undertaken in the subcommittee and presented in this discussion paper, the AESO does not believe that the current price cap level is a barrier to the FEOC operation of the energy market. Before a decision is made on whether or not to pursue further work on the price cap file, the AESO would appreciate stakeholder comments on this conclusion, as well as the specific issues, analysis and findings raised in this paper.

2.0 Price Cap Policy and Background

Numerically, the price cap is not firmly set in policy, regulation or legislation – it is an ISO rule and is within the discretion granted to the ISO. Given this, the price cap level should be set such that it is consistent with the AESO's mandate. Specifically, it should promote a fair, efficient and openly competitive (FEOC) market and help ensure system reliability.

2.1 Price Cap Background

In the vast majority of circumstances, the price cap is really an offer and bid cap because SMP is set at the highest dispatched block and offers and bids must be $0/MWh or greater and less than $1000/MWh, as articulated in ISO Rule 3.9(a). ISO Rule 6.3.9.1(a) sets out the price setting mechanism that translates the offer cap into the $999.99 price cap for normal operations.

The actual price cap is set at $1000/MWh but this can only be reached when firm load is curtailed under OPP 801 at step 31 for a complete settlement period. Notably, the SMP has only hit $1000/MWh on four occasions since the market opened in 1996: three times in 1998 and once in 2006. Nonetheless, ISO Rule 6.3.9.1(b) establishes the price cap under shortfall conditions. Price is set administratively at $1000/MWh at this point – it does not matter what the highest priced offer or bid in the market was. For example, if there are no offers above $998/MWh, price would still be set at $1000/MWh during a firm load curtailment. It should be noted that the market has never cleared at a Pool Price settle of $1000/MWh.[1]

2.2 FEOC Market and the Price Signal

The price cap relates to the concept of a FEOC market since a cap does not allow supply and demand to openly set price under certain conditions. However, a FEOC market as articulated by Alberta's policy and legislation does not require that price is set at a completely unfettered level in all circumstances.

Specifically, the DOE's 2005 Electricity Policy Framework[2] articulated a number of principles for the market, including:

> 2. The market framework must be guided and founded on fair and sustainable market and competitive forces.
>
> 3. The market framework must provide market signals to build new supply in a timely manner to meet growing demand while recognizing the lead-time required building new generation.
>
> 5. The market framework must continue to preclude the exercise of market power and unwarranted transfer of wealth.

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[1] References to "hitting the price cap" in this paper refer to the $999.99 bid/offer cap as the $1000 cap serves other purposes.

[2] Alberta's Electricity Policy Framework: Competitive – Reliable – Sustainable. Alberta Department of Energy, June 6, 2005, Page 8.

The policy framework[3] also commented on the qualities an effective price signal must have.

> "In a competitive market, generation investment decisions are made based on expectations of future market performance. This means that Alberta's electric framework must provide signals that are predictable and understandable, and it must support future investment in the electricity sector to underpin economic growth."

The framework also recognized that price caps are a response to the fact that load often cannot respond to real-time prices:[4]

> Restructuring challenges in Alberta and other jurisdictions include:
>
> …….
>
> The inability of load to respond to price, which could lead to an understandable imposition of price caps or other market power mitigation mechanisms. These mechanisms constrain wholesale prices below their competitive levels. This constraint leads to insufficient revenue to attract new investment and may even make it difficult to retain some existing generation.

The AESO interprets these policy directives as providing guidance in evaluating the level of the price cap. As such, the price cap must balance a number of competing objectives:

- Prices must be able to rise substantially above the cost of new generation for a time in order to signal the need for new investment.
- Prices must be allowed to rise high enough to ensure short term adequacy. This means the cap should be high enough to allow all generators to profitably enter the market, flexible demand to profitably curtail and import capability to be maximized.
- Small changes in the number of scarcity hours are unpredictable, largely based on the timing of forced outages. If these basically random hours have too much influence, the market signals are neither predictable nor understandable.
- Sustainability requires both sufficient generation and reasonable prices reflecting market economics.[5] If prices rise too quickly in response to relatively limited instances of scarcity, the market structure will come under public pressure.

Any price cap will impact the price unless it is never hit, and therefore 'interfere' in the open market to an extent. However, it can be argued that at the point the cap is binding, the market is no longer fair or openly competitive. Excess generation capacity is limited for the hour and very little load relative to total load has the ability to alter its

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[3] Ibid, Page 6.

[4] Ibid, Page 27.

[5] The industry has often debated what market economics are relevant in times of contingency events, forced outages creating congestion and general times when the market may be operating in abnormal circumstances. This paper is not intending to reopen that debate, yet it is clear that the price cap must be set at a level that balances the objectives.

behaviour in real-time. In recent discussions with industry, the market design has reflected this incongruence by restricting restatements during the hour. Further, for the market to be sustainable, transient instances of scarcity that will occur from time to time should not artificially impact annual price levels. On the other hand, the price cap must be sufficiently high to allow prices to reflect scarcity conditions and signal the need for investment. The AESO's conclusion is that the price cap level and other market design features as currently articulated in the ISO rules have achieved the balance necessary to allow the market to reflect scarcity without creating artificial issues.

3.0 Frequency of Price Cap Events and Out of Market Actions

The price cap level may create an issue in the market if it frequently prevents price from rising to the level necessary to clear the market.[6] In addition, price cap events are typically associated with the use of OPP 801, which means that the AESO must take actions aside from dispatching the merit order to maintain system balance. These 'out of market' actions are a concern for participants.

3.1 Data and Analysis

All analysis was done using minute to minute system marginal price (SMP), not the hourly pool price (PP) because PP tends to under represent the total time spent at the price cap. Since 2006 there has been a significant increase in the amount of time the market has seen prices near the price cap.

The installed capacity reserve margin (blue line in Figure 1) appears to play a role in the amount of time price is near the cap. However, other factors are clearly in play because similar reserve margins to 2006 through 2008 were seen in 1997 through 2000 with very few price cap events. Further, the reserve margin has increased from 2006 to 2008, and the number of price cap events increased slightly.

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[6] In fact, hitting the price cap may occur at any price cap level if some assets choose to price at the cap for dispatch management reasons associated with a must offer, must comply market. The section on generator offers starting on page 17 examines the offers that are typically seen at or near the price cap.

Figure 1 - Total Hours Alberta SMP Exceeds $900/MWh Annually

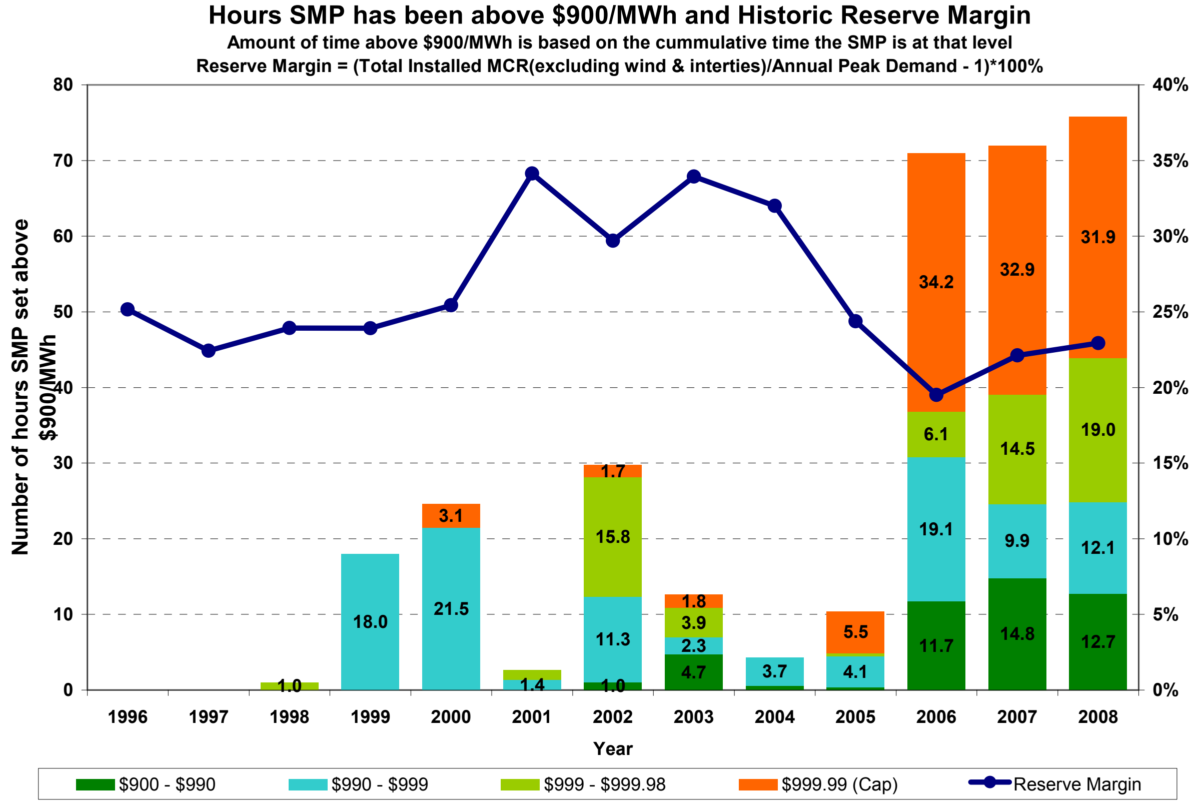
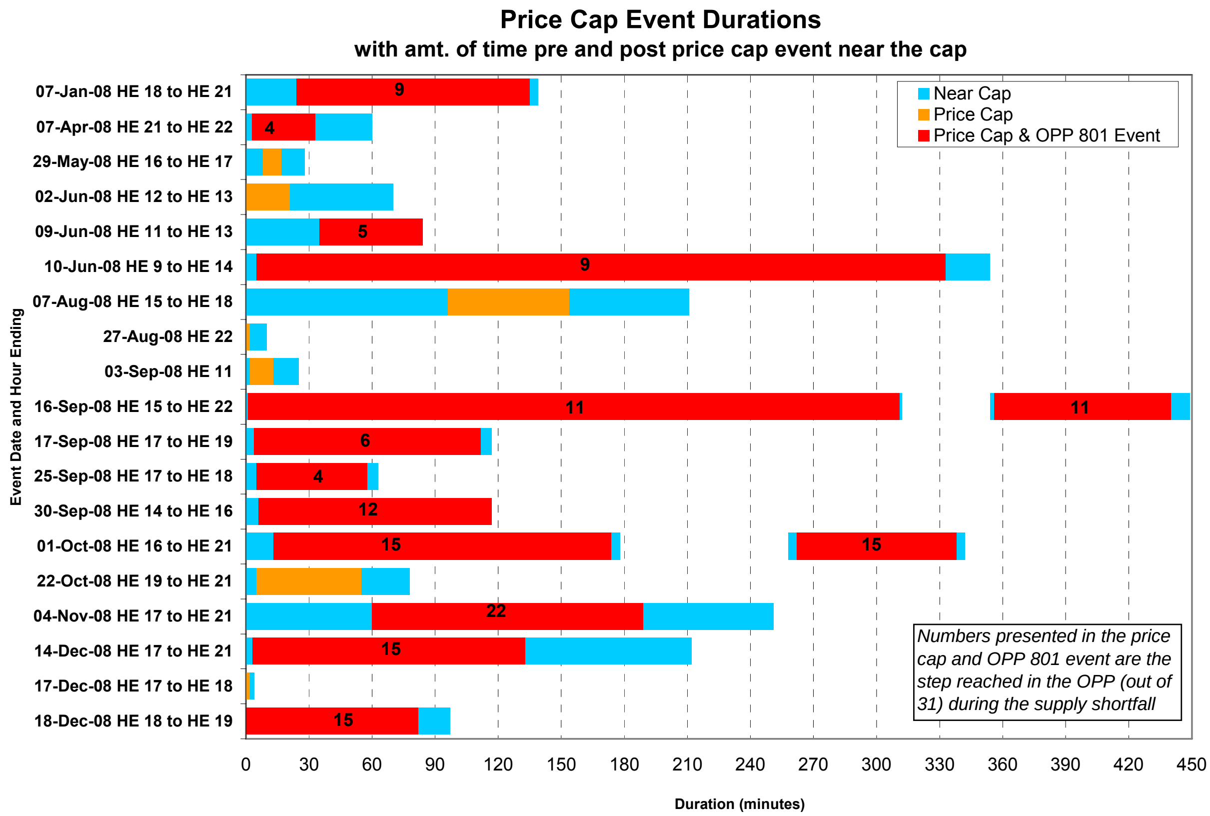


Figure 2 presents a chronological picture of the price cap events that occurred in 2008. The red portions of the bars represent time spent in OPP 801, the orange portions represent time the SMP was at the price cap but not in OPP 801, and the blue portions represent time spent below the price cap but above $900/MWh. The number in the red portion of the bar represents the highest step reached under OPP 801.

Figure 2 – 2008 Price Cap and OPP 801 Event Durations



The figure shows that if the market hits the price cap, it generally requires OPP 801 to keep the market in balance. Just over 2 hours spread over 7 events were priced at the cap without entering OPP 801. In these instances, the price cap may have altered the pricing outcome, but no out of market actions were required to balance the market.

Within OPP 801[7], step 5 is the first step where an action is taken in the market (increase import ATC to maximum given real-time market conditions). The figure shows 2 OPP 801 events did not require action greater than step 4 (notification of on-call staff), suggesting that no corrective intervention was made. From steps 5 through 17, some of the key actions taken are difficult to consider as purely out of market. For example, curtailing Demand Opportunity Service (DOS) loads (steps 6,7,8 and 9) and altering the operating reserve mix (steps 11, 12 and 13) could be viewed as in market. The market was balanced at or before step 13 in all but 4 events. Step 15, which amounts to a request to generators to ensure they are providing all available generation, cleared the market on 3 more occasions. Step 22 was required to resolve the single remaining event, and between step 15 and 22 there are actions that are quite clearly out of market interventions.

Table 1 presents a summary of the events and the number of coal units on forced or planned outages in order to provide some context for the causes of the events illustrated previously in Figure 2. Of the 19 days with price cap events in 2008, 6 of the events were directly as a result of a forced outage at a coal unit(s), 11 were a result of a

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[7] The steps from OPP 801 are included in the Appendix to this paper.

combination of planned and un-planned outages, two of which were further contributed to by intertie outages. The remaining 2 events, which occurred in December, were due primarily to high demand.

Table 1 - 2008 Price Cap Event Summary Descriptions

Event Date	Event Type	Length of Event (Min)	Directly as a Result of a Forced Outage	# of Coal Units on Forced Outage	# of Coal Units on Planned Outage	Intertie Outage	High Demand
07-Jan-08	OPP 801	111	Yes	2			
07-Apr-08	OPP 801	30		2	3		
29-May-08	Cap	9		2	2		
02-Jun-08	Cap	21		1	2	Yes, BC	
09-Jun-08	OPP 801	49		2	3		
10-Jun-08	OPP 801	328		2	3		
07-Aug-08	Cap	58		3	2		Yes – 9,020 MW
27-Aug-08	Cap	2		3	1	Yes, BC	
03-Sep-08	Cap	11	Yes	3			
16-Sep-08	OPP 801	310		4			
16-Sep-08	OPP 801	84		4			
17-Sep-08	OPP 801	108	Yes	3			
25-Sep-08	OPP 801	53		3			
30-Sep-08	OPP 801	111		3			
01-Oct-08	OPP 801	161	Yes	3			
01-Oct-08	OPP 801	76	Yes	3			
22-Oct-08	Cap	50	Yes	3	1		
04-Nov-08	OPP 801	129		2	2		Yes – 8,816 MW
14-Dec-08	OPP 801	130	Yes	3			
17-Dec-08	Cap	2					Yes – 9,652 MW
18-Dec-08	OPP 801	82		1			Yes – 9,751 MW

3.2 Conclusions

Price cap events have occurred more frequently in the past 3 years, and generally appear to be driven by an energy shortfall requiring the use of OPP 801. Very few price cap events were seen where OPP 801 was not required. OPP 801 maintained supply/demand balance without curtailing firm load (step 31) in every event save 1, which occurred in 2006. At the current reserve margin levels of 20% to 23%, just less than 1% of hours appear to be affected by the price cap and OPP 801. Further, since some of the steps within OPP 801 are not out of market interventions, hitting the price cap does not necessarily mean there has been an intervention in the market beyond setting a maximum offer price.

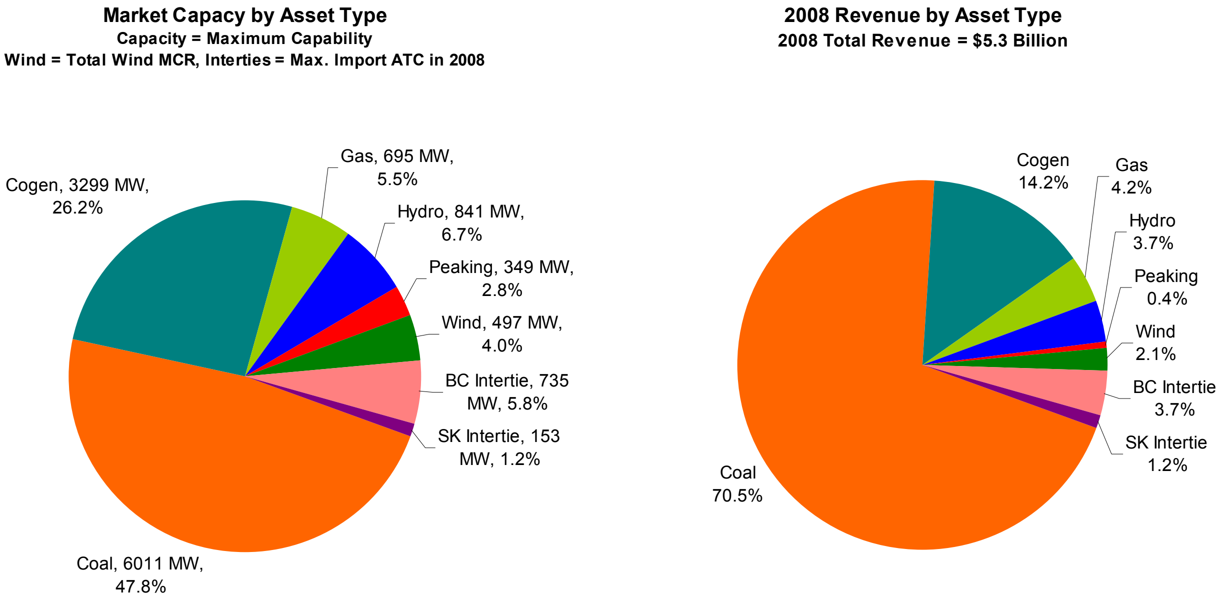
4.0 Importance of Scarcity Pricing for Generator Revenues

Scarcity pricing is an important feature in an energy only market because fixed costs (capital costs in particular) must be recovered from a single energy price signal. This is true for all generation types in Alberta.

4.1 Data and Analysis

In order to present aggregate results in this section along with all following sections, the generation in the province was grouped into one of 5 categories. Figure 3 presents a breakdown of the Alberta generation fleet based on grouping generation as one of coal, cogen, gas, peakers, hydro, wind or intertie. Intertie capacities are presented based on the maximum import ATC in 2008. The capacities of assets that offer into the market are measured by their maximum capability.

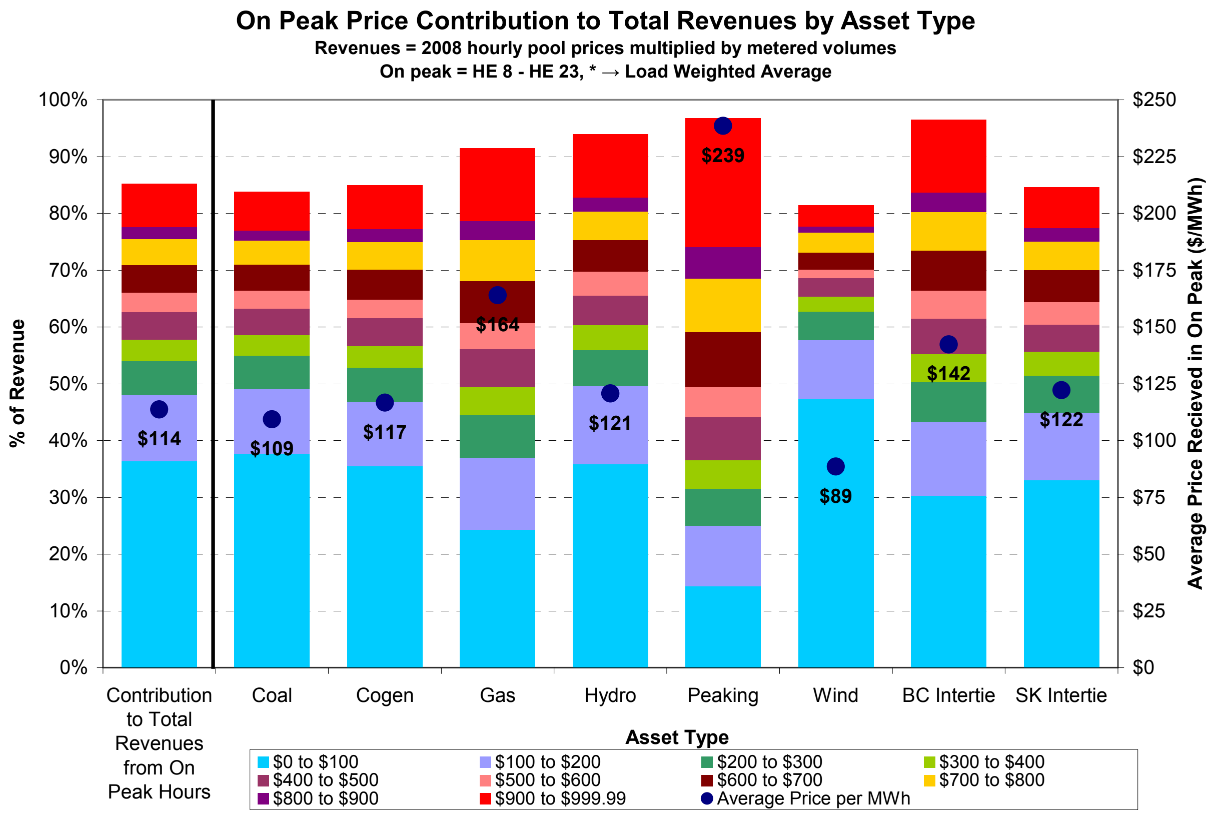
Figure 3 - Breakdown of Existing Generation Capacity Including Wind and Interties

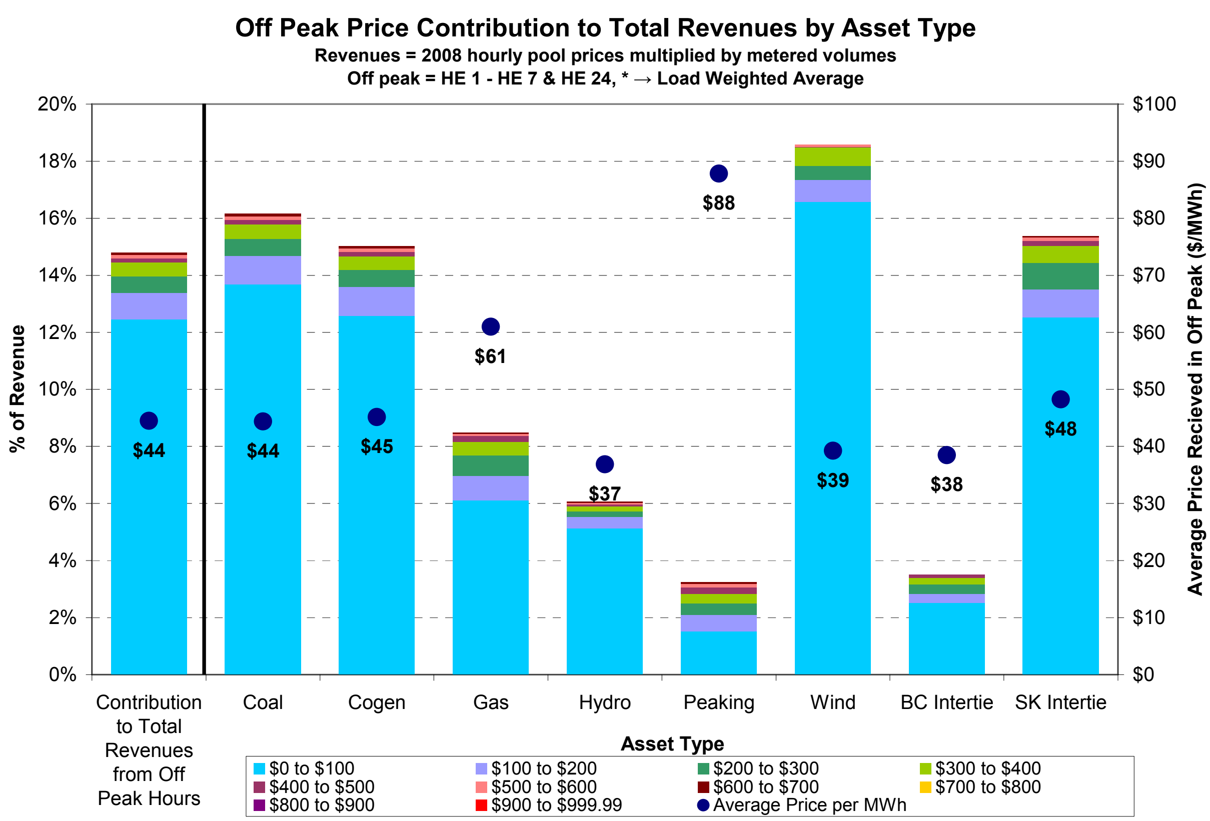


Gas units are mid merit type plants that are typified as combined cycle technology, while peakers are flexible, quick start units typified as simple cycle units. All cogen capacity was placed into the cogen category, even though some cogen capacity can act as peaking capacity.

Figure 4 presents the breakdown of revenue in on and off peak hours. The total height of the bar in each chart represents the share of total revenue that came from that timeframe, i.e. 85% of total market revenues were earned in on peak hours, which account for only 67% of the total hours in a year. All units earned at least 80% of their revenues in the on peak hours, and peakers and the BC intertie earned about 95% of their revenue in the on peak hours. The numbers placed within the bars represent the average price received during either the on or off peak period. For example, peakers received $239/MWh on average in the on peak hours, and $88/MWh in the off peak hours.

Figure 4 - Importance of Scarcity Pricing in Generator Revenues – 2008 Data





The data illustrates that in 2008, scarcity pricing was important in the overall revenue for all units. Baseload units received about half their revenue in hours over $100/MWh, and 7% to 8% of their revenue from hours with the price above $900/MWh. Gas, hydro and the BC intertie showed higher average revenues and greater reliance on high price events than the baseload units, but not to the same extent as peaking units. Peaking units received 22% of their revenue from hours with prices over $900/MWh, which is notable because these hours only accounted for about 1% of the total hours in the year.

4.2 Conclusions

Scarcity pricing is important in the Alberta market, as less than 1% of the hours contributed nearly 10% of the total revenue earned by industry. Peaking units are particularly sensitive to peak prices, and receive 22% of their total revenue in hours where the price is above $900/MWh. However, even for peaking units, the majority of revenue comes from hours when the price is below $900/MWh.

5.0 Generation Investment in Alberta

Some participants have suggested the price cap might artificially hold prices below the level required to incent new generation development despite a shortage of capacity in the market. As such, the price cap would reduce reliability by lowering the total amount of investment, and it may also alter generation investment decisions away from capacity sensitive to the price cap such as peaking units. Going forward, there is also concern that the price cap could become a barrier because generation costs are rising and possible environmental requirements will increase the price required for new generation investment.

5.1 Data and Analysis

Alberta's electricity market has experienced two broad price cycles, with the first cresting in 2000/01, and the second occurring in 2006/08. The first price cycle lasted just over 1 year and saw consistently high prices under most market conditions. However, in the first price cycle, the price very rarely hit the cap. The second price cycle lasted 3 years, and saw very high prices periodically in response to forced outages. The cap was reached just under 1% of the time in the current price cycle, a dramatically greater portion of time than in the first price cycle. Going forward, outage and reliability trends associated with an aging coal fleet could exacerbate the frequency of high price events in response to forced outages. Figure 5 presents quarterly generation development, retirement and market prices from 2000 to the present, along with annual projections for 2010 and 2011.

In the most recent price cycle (2006 through 2008), quarterly prices were near $100/MWh or higher in 5 of 12 quarters. On an annual average basis, 2008 saw the highest prices at $90/MWh. Generation projects started to come online in late 2007 and throughout 2008. Cogen and peaking units account for the majority of the capacity added recently. Cogen additions are concurrent with load additions, and the coal addition replaces retiring capacity. Peaking generation is consistent with the signal sent by high priced hours occurring with much greater frequency in 2006/08 than in previous years.

Figure 5 – Generation Investment in Alberta – 2000 through 2011[8]

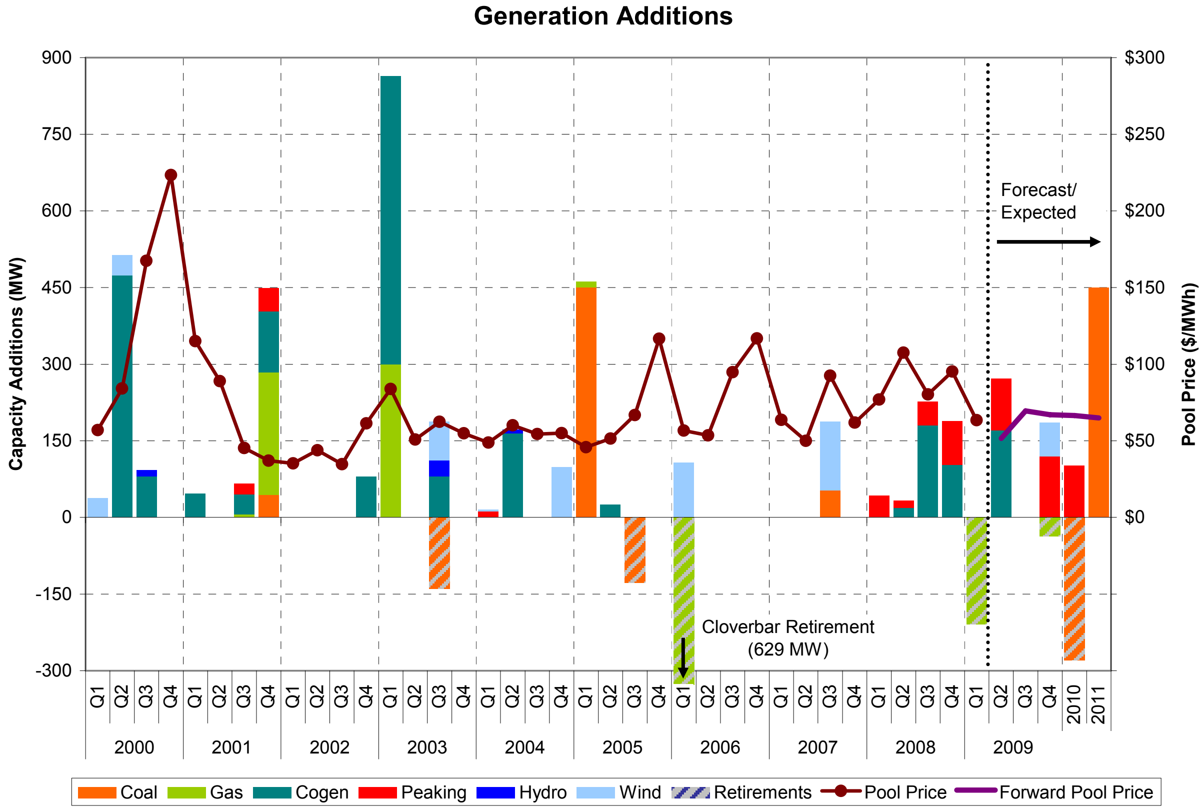


Table 2 - Estimate of Generation Returns - Alberta MSA

Plant Type	Capital Cost ($/MW)		Net Revenue (% of Capital Cost)	
	2004	2008	2004	2008
Coal	$1,777,778	$3,500,000	9%	15%
LM6000	$744,681	$1,000,000	6%	20%
Combined Cycle	$1,000,000	$1,500,000	9%	13%
Wind	N/A	$1,700,000	N/A	$0

There has been a notable cost escalation from the 2004 MSA report[9] to 2009 analysis[10] in all generation options studied by the MSA, but all options were more attractive in the 2009 analysis based on higher market prices seen in 2008.

Further analysis based on 2008 prices and a similar methodology to the MSA's report was done to consider the impact of carbon pricing on costs for thermal units. Carbon costs of $0, $10, $30, and $50 per kt CO2e were used in the analysis to determine what

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[8] Forecast information taken from AESO May 2009 Adequacy Metrics. Please see http://www.aeso.ca/market/17855.html

[9] MSA Report: Economics of New Entry, April 24th, 2004. http://www.albertamsa.ca/files/EconomicsofNewEntry042804.pdf (2004 MSA analysis based on 2002/03 price data, 2009 study based on 2008 prices.)

[10] MSA Report: 2008 Year in Review, March 17th, 2009. http://www.albertamsa.ca/files/2008_Year_in_Review_031909(1).pdf

impact the increased costs would have had on the cost of operations in 2008. The analysis assumes that there is no impact to the spot market price based on the addition of a new unit and/or the addition of carbon costs.

In addition to conventional technologies simply paying a carbon tax, a coal unit with carbon capture and sequestration (CCS) was included, based on double the capital costs of a conventional coal unit. It was assumed that a CCS coal unit did not pay any carbon costs beyond the higher capital costs. Table 3 presents the input assumptions and Table 4 presents the results, which are calculated using the same methodologies outlined in the MSA's report.

Table 3 – Assumptions for Generation Returns Analysis

	Coal	Coal CCS	Peaking	Combined Cycle
Capacity (MW)	450	450	47	250
Capital Cost ($Thousands)	$1,575,000	$3,150,000	$47,000	$375,000
Annual Fixed Costs ($Thousands)	$30,200	$60,400	$2,680	$15,000
Availability (%)	92%	92%	94%	92%
Variable O&M ($/MWh)	$1	$2	$0.50	$1
Fuel Cost ($/MWh)	$10	$10	Variable	Variable
Heat Rate (GJ/MWh)	NA	NA	10	8
Losses (%)	4.8%	4.8%	4.8%	4.8%
Starts ($/Start)	NA	NA	$300	NA
GHG Intensity (kt CO2 e/MWh)	0.85	0	0.55	0.4

The results in Table 4 illustrate that as the cost of carbon increases, the build signal lessens significantly for coal and combined cycle units, i.e. baseload capacity. The 2008 prices were unattractive for a CCS unit based on the significant capital costs. Peaking units remain viable under all the carbon cost scenarios, given 2008 price levels. The coal unit with variable generation levels is simply a standard coal unit that ramps down to 50% output if uneconomic, and shuts in production if uneconomic for 5 consecutive days.

Table 4 - Generation Returns Analysis Including Carbon Costs

	Carbon Costs ($/kt CO2e)	Total Generation (GWh)	Capacity Factor (%)	Total Revenue ($1,000)	Average Price Received ($/MWh)	Carbon Costs ($1,000)	Costs per MWh ($/MWh)	Net Revenue ($1,000)	Return on Capital (%)	% of Total Generation Running Under Uneconomic Conditions
Coal: Baseload all hours	$0	3,636.6	92.0%	$327,112	$89.95	NC	$15.32	$241,201	15.3%	2.0%
	$10	3,636.6	92.0%	$327,112	$89.95	$30,911	$23.82	$210,290	13.4%	11.7%
	$30	3,636.6	92.0%	$327,112	$89.95	$92,733	$40.82	$148,468	9.4%	23.8%
	$50	3,636.6	92.0%	$327,112	$89.95	$154,554	$57.82	$86,646	5.5%	44.7%
CCS	$0	3,636.6	92.0%	$327,112	$89.95	NC	$16.32	$207,364	6.6%	2.7%
Coal: Variable generation levels	$0	3,620.5	91.6%	$326,980	$90.31	NC	$15.34	$241,252	15.3%	1.6%
	$10	3,533.4	89.4%	$325,636	$92.16	$30,034	$23.93	$210,898	13.4%	9.1%
	$30	3,381.5	85.5%	$320,971	$94.92	$86,227	$41.06	$151,938	9.6%	18.4%
	$50	2,898.6	73.3%	$297,833	$102.75	$123,188	$58.43	$98,266	6.2%	32.6%
Peaking	$0	105.7	25.6%	$21,236	$200.87	NC	$86.72	$9,388	20.0%	8.7%
	$10	84.8	20.5%	$19,546	$230.55	466.2978	$94.27	$9,340	19.9%	10.1%
	$30	58.7	14.2%	$17,217	$293.45	968.0722	$109.03	$9,108	19.4%	7.2%
	$50	46.0	11.1%	$15,951	$346.82	1264.763	$123.41	$8,860	18.9%	3.2%
Combined Cycle	$0	1,031.6	47.0%	$140,034	$135.74	NC	$68.34	$54,532	14.5%	19.2%
	$10	893.0	40.7%	$130,611	$146.26	$3,572	$73.03	$50,392	13.4%	21.5%
	$30	677.5	30.9%	$113,684	$167.80	$8,130	$82.26	$42,951	11.5%	27.2%
	$50	603.8	27.5%	$106,193	$175.86	$12,077	$91.00	$36,244	9.7%	42.9%

5.2 Conclusions

There is no strong evidence the price cap has interfered with generation investment in Alberta. Generation investment has kept pace with demand growth, and a wide variety of generation technologies have been deployed since the market deregulated.

Investment in peaking capacity should be the most sensitive to the level of the price cap because it derives the largest portion of its revenue from high price events. Within this category of generation, about 500 MW of new capacity is expected to be added to the market between 2008 and 2010. This type of generation capacity is consistent with the price signal in the market from 2006 onwards, although many other factors play into the specific investment decision made by developers.

The data does not suggest that the price signal is failing to signify either that the market has sufficient generation capacity (2002 through 2005 generally) or that new capacity is needed (2006 through 2008 as an example). In the 2006 through 2008 period, the frequency of scarcity pricing increased and the average prices reached appear to have been sufficient to incent new generation for the 2008 through 2011 timeframe.

Going forward, the analysis does indicate that carbon costs are an increasing issue in decisions to build base-load generation. However, the price cap does not appear to be the key barrier in developing new baseload generation. The largest driver of the uneconomic results for baseload generation in Table 4 is the large number of hours potential baseload units would have operated at a loss in 2008. Typically, costs would be reflected in offers, but with a surplus of generation in some off peak hours combined with $0/MWh offers from must run generation, not all costs can be passed into the market in off peak hours. In other words, it appears that the ability to pass high costs onto the market during off peak and generally surplus hours will also be a key driver to the viability of new baseload generation in a carbon constrained world.

6.0 Market Issues – Long Lead Time Energy

Long Lead Time Energy (LLTE) is energy that requires more that one hour to synchronize to the system. This energy is available from generators that are not delivering all of their energy to the system for reasons other than an outage (LLT generators). If the price cap is too low, these units might be deterred from entering the market in a voluntary fashion because they would not expect to recover their start-up plus operating costs in the course of the price cap event. In this event, the AESO would need to resort to out of market tools to direct LLTE into the market.

The question examined in the analysis is whether units with LLTE voluntarily enter the market in anticipation of or response to price cap events if offline prior to the event. If the price cap is a barrier, there would be a tendency for LLT generators to remain offline even when the price was near the cap because the expected revenues from the event would not be enough to recover the cost of starting.

6.1 Data and Analysis

Price cap events were categorized as either short or long, with short events being those where prices were at or close to the price cap for one hour or less and the remainder being long events. For each event the response of the LLT generator was determined to be:

- Online, i.e. the unit had already decided to run prior to the event and therefore no LLTE energy existed
- Responded, i.e. the unit made its LLTE energy available prior to the event and was able to capture the price cap event, or came online just after the price cap event was observed
- Did not respond, i.e. the unit did not makes its LLTE available to the market in response to the price cap event
- Unavailable, i.e. the unit was offline for maintenance or other operational reason

The results are presented in Table 5 as percentages of the annual total events analyzed. In 2007 there were a total of 72 events analyzed (16 long, 56 short) and in 2008 there were a total of 54 events analyzed (34 long, 20 short).

Table 5 - LLTE Responses to Price Cap Events

	2007		2008	
Type of Price Cap Event	**Long Event**	**Short Event**	**Long Event**	**Short Event**
Probability(Online given Event Type)	56%	25%	53%	25%
Probability(Response given Event Type)	38%	29%	41%	55%
Probability(No Response given Event Type)	**6%**	**34%**	**3%**	**15%**
Probability(Unavailable given Event Type)	0%	13%	3%	5%

The key row in Table 5 is highlighted in orange: this row represents a lack of response to a price cap event from an LLT asset. The table illustrates that well over 90% of the time, an LLT generator responds to a price cap event that lasts more than 1 hour. The LLT unit also responds to the majority of short duration (< 1 hour) events, even though by definition the unit would not be available until after the event was already over.

A second issue apparent from the table is that price cap events are not very predictable for LLTE. Given that LLT units respond to price cap events at a very high rate, it is very likely these units would prefer to be online when the price cap event started. However, LLT units are only online at the start of a price cap event about 1/3 of the time across both long and short events. Even long events appear to be unpredictable as the LLT units are only online about 55% of the time prior to a long duration price cap event.

6.2 Conclusions

The results are not consistent with the idea that the price cap itself is a barrier for LLTE. LLT units respond to a price cap event the vast majority of the time that the event lasts greater than 1 hour. For events less than 1 hour, the units still typically respond, even though by definition LLTE takes more than 1 hour to synchronize to the system. It is worth further study to determine if the improvement in response during 2008 for short events was due to Quick Hits or some other factor.

7.0 Market Issues - Generation Offers and the Price Cap

A price cap also acts as an offer cap, and an offer cap may not allow generators to fully reflect their costs and the market value of electricity. Alberta's must offer, must comply rules mean that all generators must make an offer to generate, and the presence of an offer cap might create a distortion in the merit order. If a large number of generation offers are made at or near the price cap, this could reflect an issue created by the existing price cap level.

7.1 Data and Analysis

The graphs below represent the average amount of generation offered at or near the price cap over the past 12 months. The results are aggregated by the generation types outlined previously, and presented on a monthly average basis for the on and off peak periods.

At a high level, Figure 6 illustrates that more capacity is priced at or near the price cap during off peak periods. Notably, as shown in Figure 4, off peak prices did not reach above $800/MWh in off peak periods during 2008, i.e. these offers never came into merit. A portion of these price cap offers are made at lower price levels in the on peak, though about 200 MW to 350 MW of capacity is still priced at or near the price cap in the on peak.

Hydro and LLT units account for the majority of offers at or near the price cap. Hydro units are unique in that they are energy constrained rather than capacity constrained. These units price at or near the cap due to a desire to be near the top of the merit order in order to reflect the scarcity value of their limited energy storage.

LLT units price at or near the cap only when they are in an offline state. This likely reflects their desire not to start and produce electricity unless prices are sufficiently high to justify expending start-up costs. Cogen offers at or near the price cap likely reflect an operational desire to not produce the available energy.

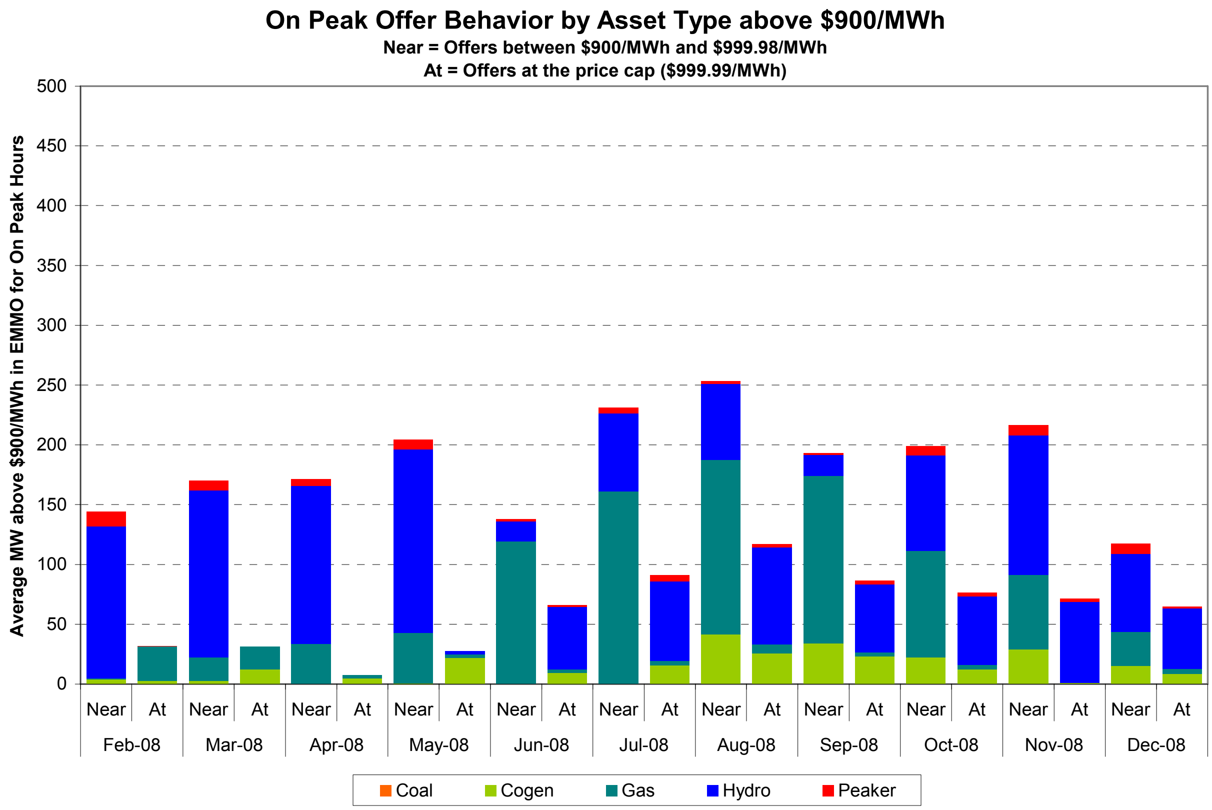
Very little peaking, coal or non LLT gas fired generation is priced at or near the price cap. For these units, the cap does not appear to limit the offers in practice.

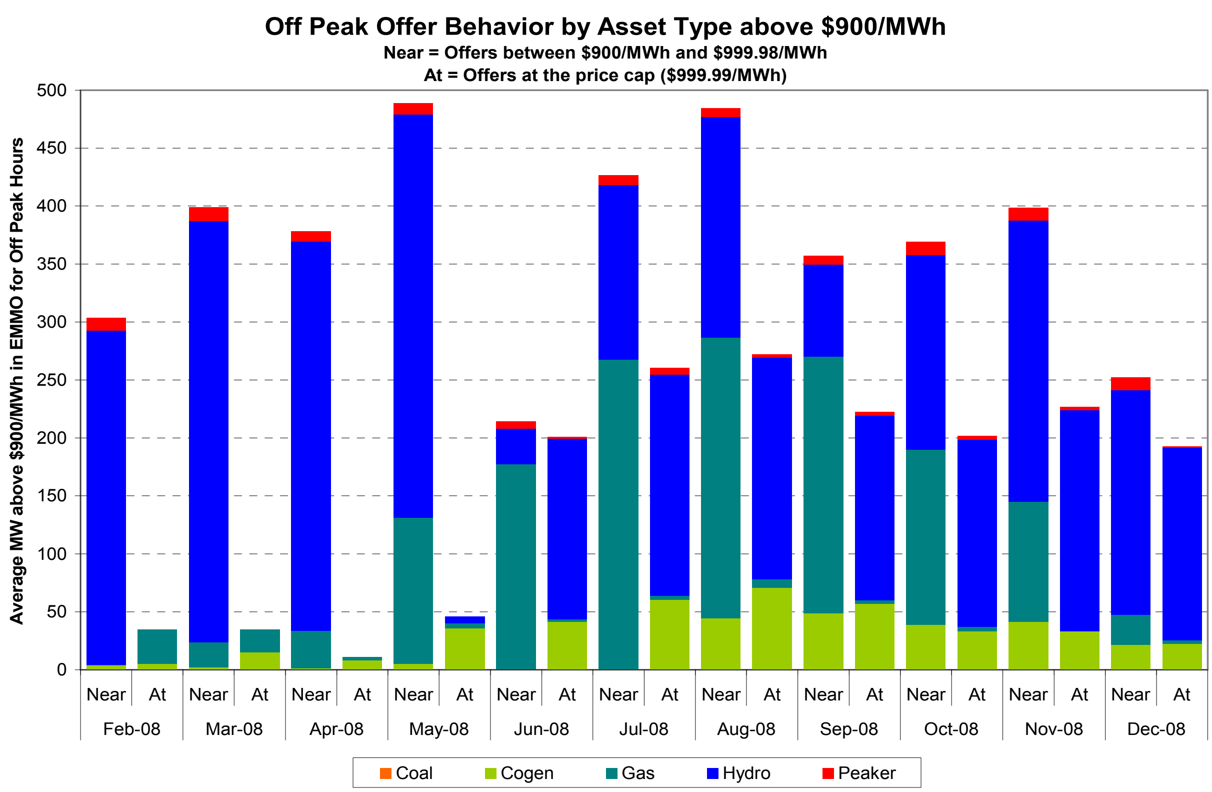
7.2 Conclusions

The analysis does not strongly support the position that the price cap is interfering with generation offers. Offers at or near the price cap appear to be driven by numerous factors, including physical realities for several units (primarily hydro, cogen and LLT units). The must offer, must comply rules are also an important factor behind some of the offers at or near the price cap, as generators may wish to stay offline but are obligated to put an offer into the market. Peaking generation does not appear to price near the cap significantly often, and less than 3% of total peaking capacity has priced at or near the cap since the must offer must comply rules were implemented.

The total volumes of energy priced at or near the price cap are not insignificant, but it is not clear there is a distortion being created by the current cap. In on peak hours, 2% to 4% of offers are typically priced at or near the price cap. For comparison, about 65% of offers are priced at $0/MWh, which relates back to the conclusion in the generation development section that passing costs through to the market in off peak hours may be a difficult problem for future investment.

Figure 6 - On and Off Peak Generation Offers – Feb 2008 to Dec 2008





8.0 Market Issues - Intertie Utilization

The price cap creates an issue in the market if it does not provide sufficient incentive for the intertie to be fully utilized for imports during price cap events. This would be indicated by unused ATC in hours when the price is at or near the cap. Unused intertie capacity could lead to more frequent scarcity events and possibly a greater need for out of market interventions by the AESO.

8.1 Data and Analysis

The analysis examined intertie utilization during hours when the pool price exceeded $900/MWh, as well as hours when the SMP exceeded $900/MWh for at least one minute.

In general, the BC intertie has been very well utilized during price cap events since 2005. Utilization was nearly 90% when the hourly price settled above $900/MWh on average across the 2005 through 2008 timeframe. Although the 2004 results indicate poor intertie utilization, they are based on a sample size of only a single hour.

In hours with at least one minute of SMP > $900/MWh average utilization approached 80% across the entire period for the BC intertie.

The Saskatchewan intertie was less well utilized than the BC tie during price cap events, but still averaged 60% to 80% utilization during hours where the pool price settled above $900/MWh.

Table 6 - Utilization of the BC Intertie During Price Cap Events

	# of Hours			Average Utilization				BC Import ATC (MW)	
Year	Total	w/ SMP ≥ $900	w/ PP ≥ 900	In Hours With SMP < $900	In Hours With PP < $900	In Hours With SMP ≥ $900	in Hours With PP ≥ $900	Max	Average
2004	8,784	23	1	45%	45%	55%	47%	725	555
2005	8,760	39	4	45%	45%	73%	85%	715	604
2006	8,760	146	53	44%	44%	76%	96%	700	607
2007	8,760	134	52	49%	49%	71%	79%	675	517
2008	8,784	127	60	66%	66%	89%	94%	625	468

Table 7 - Utilization of the SK Intertie During Price Cap Events

	# of Hours			Average Utilization				SK Import ATC (MW)	
Year	Total	w/ SMP ≥ $900	w/ PP ≥ 900	In Hours With SMP < $900	In Hours With PP < $900	In Hours With SMP ≥ $900	in Hours With PP ≥ $900	Max	Average
2004	8,784	23	1	32%	32%	50%	65%	153	147
2005	8,760	39	4	38%	38%	56%	58%	153	139
2006	8,760	146	53	33%	33%	51%	71%	153	141
2007	8,760	134	52	42%	42%	63%	81%	153	146
2008	8,784	127	60	52%	52%	57%	60%	153	148

Event analysis indicates that in those hours where intertie is not fully utilized, it is because intertie schedules are not flexible within the hour. For events that persisted beyond a portion of an hour, import utilization was higher than the figures shown in the table.

8.2 Conclusions

Intertie utilization does not appear to be limited by the price cap. Intra hour flexibility appears to be the largest barrier to increasing import flows during price cap events, but they are able to forecast high priced events to an extent. The data does not suggest that out of market interventions are created by a lack of intertie utilization due to the price cap.

9.0 Market Issues - Price Responsive Load

It has been suggested that the $1000/MWh price cap limits the ability of load to respond to the price signal. This could be indicated if the majority of the price response occurs at or near the price cap. Within the context of historical data analysis, it is not possible to determine whether price responsive load potentially exists that would curtail consumption at price points higher than $1000/MWh.

9.1 Data and Analysis

The AESO tracks several price responsive loads that typically reduce electricity consumption by 100 MW to 300 MW depending on the price and event duration. The price responsive loads typically begin to reduce consumption when the price rises above $100/MWh. The price responsive loads tracked generally account for 300 MW to 400 MW of load prior to an event, and a minimum of 60 MW of load after a full response.

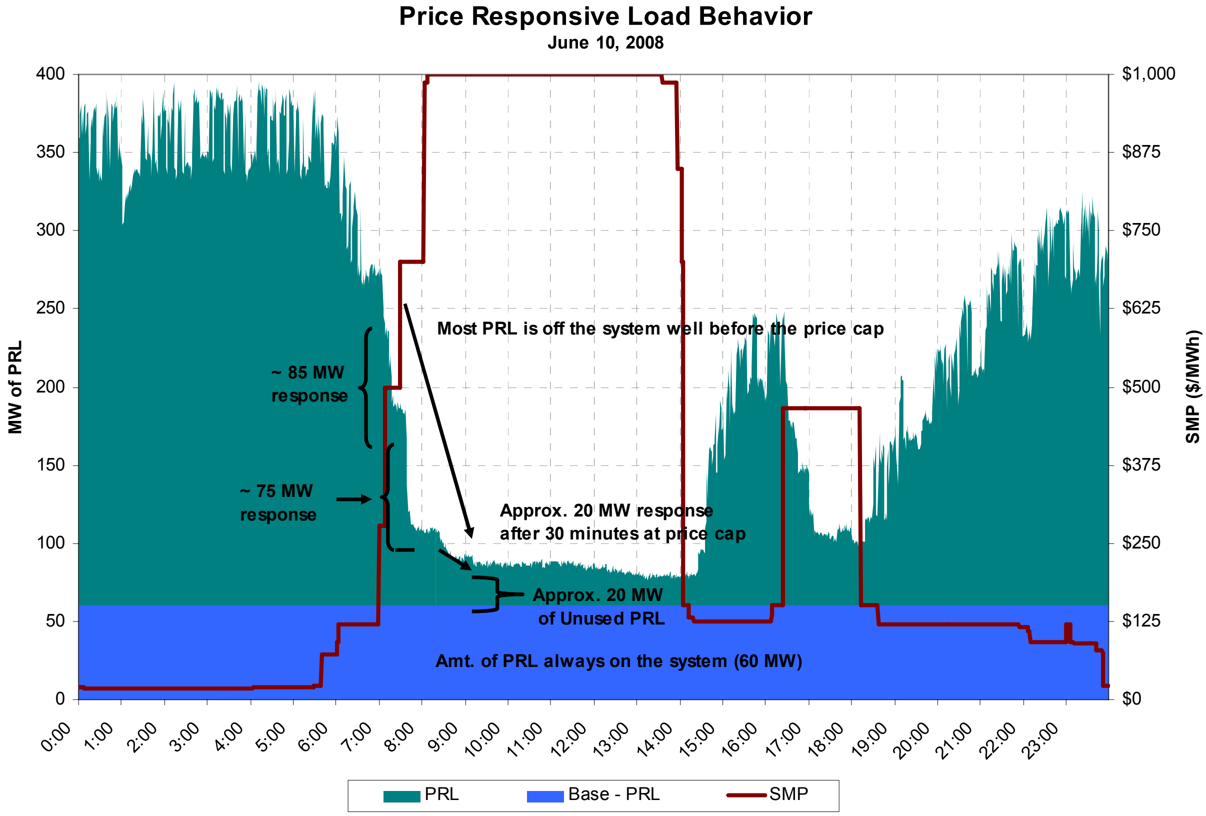
In 2008 the average response of the aggregate group of price responsive loads was approximately 200 MW. About 75% of the response occurred at prices below $500/MWh, with prices above $500/MWh eliciting another 50 MW of price responsive load, and by $900/MWh, 85% to 90% of the potentially price responsive load had reduced its consumption.

Figure 7 presents an example of the voluntary price responsive load behavior during a price cap event.

9.2 Conclusions

The analysis indicates that the majority of identified price responsive load actively tracked by the AESO has curtailed consumption prior to price hitting the cap. About 10% to 15% of the available responsive load appears to respond at or near the cap while the remaining begins to respond at prices between $100/MWh and $300/MWh. For the loads actively tracked by the AESO, the price cap does not appear to be a barrier to demand response. As noted, the analysis cannot determine how much additional demand response might occur if the price cap was increased.

Figure 7- Typical Load Response to a Price Cap Event – June 10 2008



10.0 Other Market Review

Three other markets were also examined to provide context for the price cap. This review was not done in order to assess different market models, but rather to gain an understanding of the factors that have influenced the price cap design or design changes in other markets.

Australia's market design is the most similar to the Alberta market design, but shows somewhat different outcomes in market prices. The Australian model uses a pool design similar to Alberta with an SMP based on the highest priced generation offer dispatched. However, Australia is made up of several submarkets with unique prices, although in many hours the prices are very similar because the interconnections are sufficient to arbitrage the price difference between connected jurisdictions. The Australian market generally experiences low prices in a large number of hours, and a significant portion of generator returns rely on a very small number of high priced hours. Australia experiences high prices much less frequently than Alberta, despite overall reserve margins that are very similar.

Australia has not seen a growth in demand response during the development of its market, and currently has just over 100 MW of reliable demand response. The key difference is Australia on the demand side is that as much as 90% of load is reported to be contracted, and forward prices tend to reflect a premium over average spot prices. The level of contract cover may be related to the risk in the spot market associated with a $10,000/MWh price cap.

ERCOT is another market generally compared to Alberta because it is an energy only design. However, ERCOT is largely a bilateral market, and about 95% of total energy is scheduled outside of the spot market. The spot market exists mainly to balance energy and deal with congestion. The price outcomes with respect to the price cap are quite similar in ERCOT and Australia. High prices (>$500/MWh for example) are much rarer in ERCOT than in Alberta, despite a generally lower reserve margin. One explanation is that the relatively low load factor in Australia and ERCOT combined with the generation diversity inherent in a large market result in much fewer hours where scarcity can be priced into the market.

Load participation in ERCOT is substantial and appears to be driven by the market structure. Load is very active in both the reserves market and competes with generation on an equal footing. Load is capped at supplying 50% of total reserves and often reaches this cap. Load is also very active in the spot market via contracts with load serving entities (LSEs). LSEs have financially binding schedules and can use load response to manage their position in the spot market. Many LSEs offer contracts that incent loads to be responsive to a variety of conditions.

Netherlands illustrates a model that reduces the importance of the price cap in the spot market. Generators and loads (or load serving entities) have a requirement to submit financially binding balanced schedules prior to the operation of the imbalance market. This dramatically reduces the incentive to make high priced offers because both sides of the market are equally exposed to the risk of very high prices in the imbalance market. Further, the impact of high prices in the imbalance market is dramatically mitigated because 95% or more of energy is traded in the forward market.

For a detailed review of the individual markets summarized, please see the Appendix.

11.0 Conclusions and Next Steps

The AESO's review of the $1000/MWh price cap in Alberta suggests that the price cap is not a barrier to the competitive operation of the market.

Generation investment in Alberta has been adequate to date and the price cap does not appear to pose a barrier to supply adequacy. The price signal in the most recent price cycle (2006 through 2008) was sufficiently high to create economic returns for new generation from a variety of fuel sources, and generation development plans during this timeframe appear to be sufficient for expected demand growth plus retirements.

Carbon costs may pose an issue in the future, but scarcity pricing does not seem like the key element that must be addressed. 2008 prices were sufficient to create economic returns for peaking generation even with very high carbon costs, and renewable generation sources would also likely benefit from a carbon constrained policy. Baseload generation, particularly coal generation, would require higher prices than the market delivered in 2008 in order to be economically viable. However, the key barrier for new baseload generation appears to be the preponderance of low priced hours in which baseload units might operate at a loss unless carbon costs can be passed through to the market rather than a lack of high priced hours.

Several possible barriers to the competitive operation of the market associated with the price cap were identified in the scope of this study, but the market data suggests that the price cap is not the source of the perceived problem. Long Lead Time (LLT) generators enter the market the large majority of the time when price approaches the cap, particularly when the event persists for greater than 1 hour. The largest barrier for LLT units appears to be a combination of the unpredictability of price cap events combined with the units' prolonged physical start time.

Intertie utilization was identified as an area where the price cap might have a negative impact. However, the analysis suggests that the intertie is well utilized during price cap events, and to the extent there is unused capacity, the T – 2 timeframe for scheduling is the key issue. Interties cannot respond to price signals inside of this timeframe, and price cap events are often quite unpredictable.

Analysis of demand responsiveness shows that the majority of existing demand response is offline prior to price reaching the cap. Although the analysis cannot be extended to determine if more demand response exists at higher price levels, the price cap does not seem to be a barrier for the current load active in the market. Surveys from ERCOT suggest that unpredictability, short notice and short duration price spikes are key barriers to demand responsiveness, which is likely also true in Alberta. Markets such as ERCOT appear to attract more demand response in part due to the market design which forces loads to participate in the market even if they do not plan to actively respond to price signals.

As a next step, the AESO is seeking feedback on the analysis and conclusions contained in this discussion paper. In particular, the AESO would appreciate stakeholder feedback on whether the level of the price cap creates a barrier to the operation of the Alberta electricity market. Please provide comments to Kris Aksomitis (Kris.Aksomitis@aeso.ca) by July 17th using the attached comment matrix.

Appendix: Other Market Price Cap Review

Three markets were reviewed as part of the price cap analysis: Australia, ERCOT (Texas) and the Netherlands. Market design, price outcomes and other relevant factors were reviewed, pending information availability. The market reviews are high level overviews, and are intended to inform the broad discussion of price caps in electricity markets.

Australia (NEMMCO)

The National Electricity Market (NEM) represents the wholesale electricity market and the associated synchronous electricity transmission grid in Australia. The NEM was established on December 13th, 1998, and incorporates Queensland, New South Wales, the Australian Capital Territory, Tasmania (as of May 2005, fully operational on April 29, 2006), Victoria, and South Australia. The average load is around 45,000 MW, or roughly 6 times Alberta's market.

Australia is primarily a thermal market, with an even heavier balance towards coal generation than Alberta. About 85% of energy production in Australia is coal powered, with natural gas and hydro generation accounting for about 8% each.

The Australian market design is quite similar to the Alberta design, as both are energy only markets with a pool based spot market. Generators in Australia have similar freedom to offer price quantity pairs in Australia as is done in Alberta, and relatively few restrictions are placed on offers. The key difference as compared to Alberta is that Australia is broken up into 5 sub-markets (6 prior to the Snowy region being incorporated into the NSW region in July 2008) that are interconnected, but each sub-market has a local price.

Market Fundamentals

<u>Prices</u>

Australia's price cap is currently set at $10,000/MWh (all prices in Australian dollars), and the price floor is set at -$1,000/MWh. The price cap level is set at the estimated value of lost load, or VOLL. The price cap was raised from $5000/MWh in April 2002, and there are plans to raise the price cap to $12,500/MWh in July 2010.

There is also a secondary price cap known as the cumulative price threshold (CPT), which lowers the price cap to $300/MWh when the rolling 7 day average price exceeds approximately $450/MWh.[11] This threshold has been exceeded several times in the past 2 years, most recently in January 2009.

Electricity prices have been very low in Australia over the past 9 years, despite several generation shortages that resulted in blackouts during heat wave events. Prices have generally ranged, on an annual average basis, from $25/MWh to $45/MWh. 2007 was the major exception, as spot prices averaged in the mid $60/MWh range across Australia.

[11] http://www.nemmco.com.au/powersystemops/150-0075.pdf

Table 8 highlights the annual average prices from 2000 through 2008 from the 4 main Australian regions, along with the average excluding the top and bottom 1% of price. South Australia prices in 2008 show the impact a $10,000/MWh price cap can have on a market, as the average price in that market was $66/MWh, as compared to prices around $40/MWh in neighboring markets. The trimmed average prices show that South Australia had similar prices as its neighbors the majority of the time, but the top 1% of hours added $30/MWh to the average price, as compared to adding around $10/MWh as occurred in the other Australian markets.

Table 8 - Historical Australian Prices

				Annual Average Price					
	2000	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
NSW	$35.63	$33.27	$39.76	$26.40	$45.14	$35.83	$31.01	$67.07	$39.14
QLD	$50.39	$34.97	$47.82	$22.52	$34.51	$25.17	$25.97	$66.84	$43.87
SA	$56.94	$42.15	$35.32	$26.66	$41.61	$33.60	$38.68	$57.50	$66.37
VIC	$38.23	$36.01	$33.15	$23.10	$30.04	$26.29	$34.13	$63.40	$40.23
				Annual Trimmed Average Price (Top and bottom 1% of Prices are removed)					
	2000	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
NSW	$31.40	$29.53	$29.58	$19.65	$29.05	$23.74	$25.34	$53.63	$34.11
QLD	$38.79	$30.74	$30.77	$17.74	$26.56	$20.27	$21.15	$52.25	$31.19
SA	$43.27	$30.81	$29.46	$24.18	$33.18	$29.23	$31.87	$52.28	$36.81
VIC	$32.38	$28.28	$27.57	$20.26	$27.16	$23.78	$27.14	$53.14	$37.10

Market prices in the 4 key regions have not always converged on an annual basis, suggesting that the intertie capacity within the country is sometimes but not always sufficient to allow full price arbitrage.

Table 9 illustrates the relative frequency of prices in different price ranges during 2008, along with the portion of total energy revenues that occurred during those same hours. The highlight is the finding that in 2008, nearly 50% of total revenues in South Australia occurred in about 0.25% of the hours. Generally, the results show that the highest priced 1% of hours account for 13% to 60% of total revenues in Australia, which at the low end is similar to Alberta but at the high end illustrates the impact of a much higher price cap.

Table 9 – 2008 Australian Pricing Summary

				Percent of Time in Different Price Ranges				
2008	<$100	100 - 500	500 - 1000	1000 - 2500	2500 - 5000	5000 - 7500	7500 - 9000	> 9000
NSW	99.146%	0.746%	0.023%	0.040%	0.000%	0.023%	0.006%	0.017%
QLD	98.890%	0.786%	0.063%	0.108%	0.051%	0.046%	0.034%	0.023%
SA	98.509%	1.144%	0.011%	0.028%	0.011%	0.017%	0.034%	0.245%
VIC	98.674%	1.247%	0.011%	0.046%	0.006%	0.000%	0.017%	0.000%

				Percent of Revenue Earned in Different Price Ranges				
2008	<$100	100 - 500	500 - 1000	1000 - 2500	2500 - 5000	5000 - 7500	7500 - 9000	> 9000
NSW	83.6%	3.1%	0.4%	1.9%	0.0%	4.3%	1.7%	5.0%
QLD	64.8%	2.8%	1.3%	4.6%	4.8%	8.0%	7.9%	5.8%
SA	40.3%	3.0%	0.1%	0.8%	0.6%	2.2%	5.3%	47.7%
VIC	86.7%	5.3%	0.2%	2.4%	0.5%	0.0%	4.9%	0.0%

Overall, electricity prices in Australia have been quite low on average since 2000. In a coal dominated market with a relatively low load factor (see Table 10there are quite likely large numbers of hours with excess capacity, which typically results in low prices. As shown in Table 9, Australian prices were below $100/MWh about 99% of the time in 2008, which compares to 84% for Alberta in 2008. High prices occur with much less frequency in Australia than in Alberta, but when they do occur they are higher due to the different price cap. Prices above $500/MWh occur less than 0.5% of the time in Australia, as compared to over 2.5% of the time in Alberta.

Generation Supply and Demand Growth

Australia has seen extremely strong demand growth since 2000, particularly in terms of the peak load. Peak demand has increased by an average of about 25% across the various regions, and the non-coincident peak load reached about 71,000 MW in 2008.

Table 10 - Australian Demand Summary

Average Demand									
	2000	2001	2002	2003	2004	2005	2006	2007	2008
NSW	15,683	15,917	16,282	16,495	16,905	17,156	17,768	17,889	17,937
QLD	9,618	10,061	10,456	10,720	11,134	11,502	11,659	11,772	11,881
SA	2,910	2,943	2,947	2,927	2,935	2,868	2,990	3,048	3,055
VIC	10,559	10,740	10,847	11,121	11,289	11,340	11,692	11,834	11,913
Peak Demand									
	2000	2001	2002	2003	2004	2005	2006	2007	2008
NSW	23,644	23,426	24,148	24,663	25,676	25,768	26,377	27,625	28,548
QLD	12,686	13,167	14,209	14,430	15,927	16,464	16,590	17,177	16,826
SA	5,293	5,666	5,207	5,574	5,138	5,207	5,746	5,708	6,160
VIC	15,433	16,038	15,163	17,048	15,913	16,827	17,359	17,773	19,403
Average Load Growth									
	2000	2001	2002	2003	2004	2005	2006	2007	2008
NSW	--	1.5%	2.3%	1.3%	2.5%	1.5%	3.6%	0.7%	0.3%
QLD	--	4.6%	3.9%	2.5%	3.9%	3.3%	1.4%	1.0%	0.9%
SA	--	1.1%	0.2%	-0.7%	0.3%	-2.3%	4.2%	1.9%	0.2%
VIC	--	1.7%	1.0%	2.5%	1.5%	0.5%	3.1%	1.2%	0.7%
Peak Load Growth									
	2000	2001	2002	2003	2004	2005	2006	2007	2008
NSW	--	-0.9%	3.1%	2.1%	4.1%	0.4%	2.4%	4.7%	3.3%
QLD	--	3.8%	7.9%	1.6%	10.4%	3.4%	0.8%	3.5%	-2.0%
SA	--	7.1%	-8.1%	7.0%	-7.8%	1.4%	10.3%	-0.7%	7.9%
VIC	--	3.9%	-5.5%	12.4%	-6.7%	5.7%	3.2%	2.4%	9.2%

Supply has increased in response to the demand growth, but it has not kept pace and as a result reserve margins in Australia have generally been falling over the past 10 years. There is also concern that generation development is being influenced by government. In Queensland, the government both provided financing for new plants and actually built plants[12], while in New South Wales the government is the dominant generation developer.[13] Notably, these are the two regions that have added the majority of generation built in Australia, as shown in Table 11.

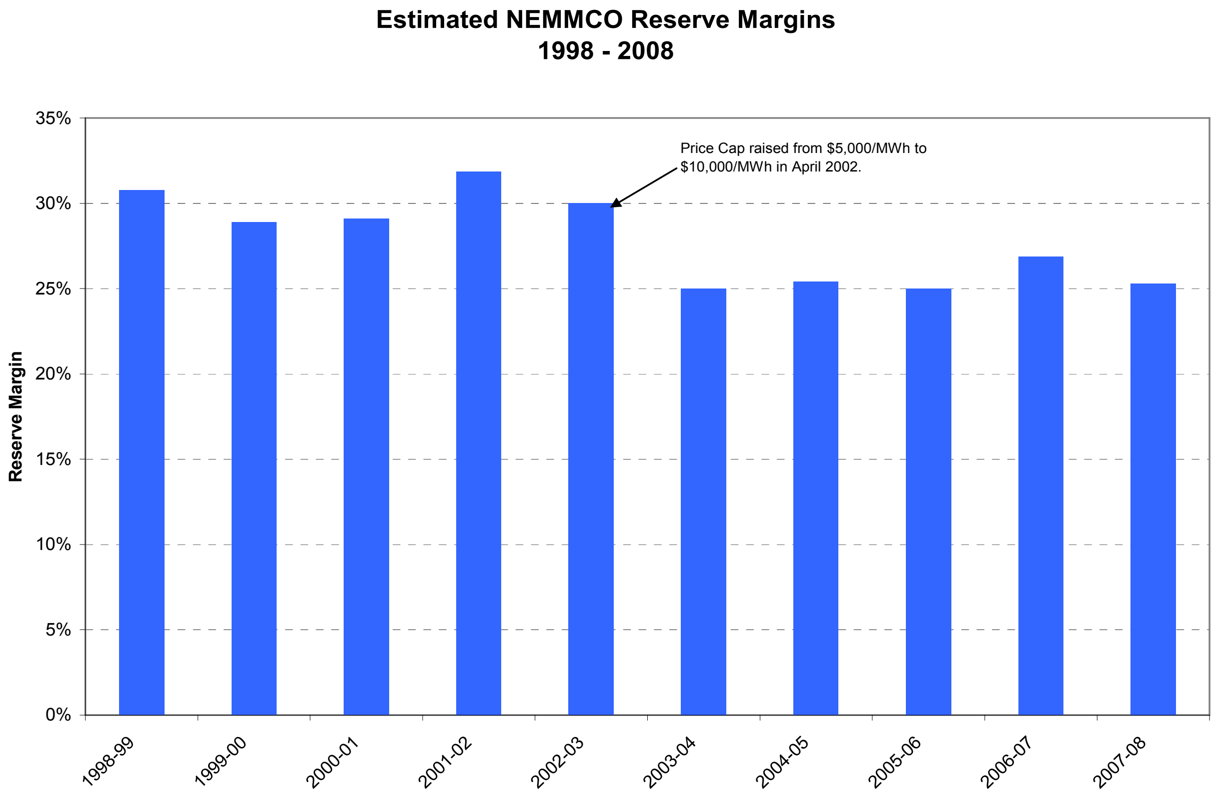
Table 11 - Installed Capacity and Peak Demand Growth

	2002/2003	2008/2009	Incremental Generation	Peak Demand Growth
QLD	9,844	11,100	1,256	2,617
NSW	14,040	15,688	1,648	4,400
VIC	10,031	9,787	(244)	4,240
SA	3,144	3,755	611	953
TOTAL	37,059	40,330	3,271	12,209

[12] Electricity Market Reform – An International Perspective. Shioshansi and Pfaffenberger. Page 201.

[13] Anthony D. Owen, Energy Policy 37 (2009), pp 570-576.

Figure 8 - Annual Australian Reserve Margins[14]



Demand Side Behaviour

Forward contracting in Australia is variously reported to be between 70% and 90%[15], i.e. only about 20% of energy would trade in the spot market. Forward prices for annual contracts appear to have a premium of $9/MWh in the on peak periods and $3/MWh in the off peak periods relative to the spot prices actually realized for the same period.[16] The suggestion is that the premium in the forward market represents an insurance premium for retailers in that spot prices can rise to extremely high levels under extreme circumstances, but these circumstances are sufficiently rare that they are not reflected in average energy prices.

In terms of demand side response in the actual physical market, Australia has very limited participation. About 110 MW of demand actively participates in the market as is considered as committed in that it is counted as a resource by NEMMCO.[17] Another 500 MW of demand participates to some degree, but is not considered committed. The

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[14] Australian Energy Regulator, State of the energy market 2008, viewed at: http://www.aer.gov.au/content/item.phtml?itemId=723386&nodeId=ee6d9d711d9a93ea4efa098f4534cae8&fn=Chapter%201%20Electricity%20Generation.pdf

[15] Electricity Market Reform – An International Perspective. Shioshansi and Pfaffenberger. Page 201.

[16] E.J. Anderson et al., Energy Policy 35 (2007), page 3099-3100.

[17] NEMMCO, Statement of Opportunities 2008, pages 5 – 6.

level of price responsiveness has not changed in NEMMCO to a large degree over the past decade, although there is currently a push to increase demand-side participation. As part of this push, smart metering is being phased in. Market rules are in the process of being changed to allow this roll-out, and the first substantial installations of smart meters are expected to occur in 2010.

Conclusions

The Australian market is quite similar to the Alberta market in terms of the market design and the preponderance of baseload generation, particularly coal. Australia's price cap is 10 times higher than Alberta's, but it is very seldom reached.

Price levels in Australia are very low on average, and some market participants have suggested that government activity in the market has resulted in prices that do not achieve commercial returns. The generation development record in Australia does not appear to demonstrate a benefit associated with raising the price cap, as the reserve margin has generally fallen since 2002 when the cap was increased. Further, the South Australia/Victoria region has not attracted sufficient generation to avoid falling below its low reserve margin condition point in 2008/09, as defined by NEMMCO.[18] However, NEMMCO did not take action via its reserve energy and reliability trader (RERT) program because it estimated total unserved energy would not exceed targets.

Forward contract prices appear to be somewhat higher than spot market prices, possibly reflecting a risk premium retailers face in that both demand and spot market prices are sensitive to hot weather events. In order to protect against exposure to the very high spot prices that can occur during these events, retailers may be willing to pay a contract premium. This risk factor may also be a factor in the level of contract coverage in Australia, which has been reported as high as 90%.

The high price cap in Australia does not appear to have increased the amount of load responsiveness in the real-time market. Incremental load response did not appear to enter the market after the price cap was raised from $5,000/MWh to $10,000/MWh, and roughly 110 MW of load reliably continues to participate in the market.

ERCOT (Texas)

The Electric Reliability Council of Texas (ERCOT) is responsible for the reliable operation of the grid and market place for approximately 85% of the state's electric load. The regulatory body responsible for overseeing ERCOT and the operation of the wholesale electricity market in Texas is the Public Utility Commission of Texas (PUCT).

The ERCOT wholesale electricity market relies on an "Energy Only" design to ensure resource adequacy. ERCOT incorporates a bilateral market that is largely operated outside of the influence of the system operator, as well as a real time balancing energy and ancillary services markets that are operated by ERCOT.

The bilateral market accounts for almost 95% of the total electric energy served. Market participants are required to submit their schedules of energy to ERCOT through qualified-scheduling entities (QSEs). The QSEs submit schedules that specify total generation and demand at the zonal level for every 15 minute settlement interval. The

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[18] Ibid, page 7.

schedules submitted by each QSE consist of schedules for their bilateral transactions with total generation and demand (at the zonal level), and bid curves for zonal balancing up and balancing down energy. ERCOT compares the sum of schedules submitted by the QSEs to its own load forecasts, and then determines from this the requirements for balancing energy and ancillary services.

ERCOT operates the Balancing Energy market, which serves the remaining electricity requirements resulting from imbalances of the bilateral generation and load schedules, accounting for approximately 5% of electricity provided. The balancing energy market is arranged every 15 minutes between generators and ERCOT based on bids submitted to ERCOT. The bid price of the last quantity needed based on a forecast of system requirements and transmission congestion sets the Market Clearing Price for Energy (MCPE) for that 15 minute interval. This is determined at a zonal level if transmission congestion exists.

ERCOT purchases balancing energy up/down bids from zones to resolve zonal congestion. Zonal congestion costs are directly assigned based upon cost causation, thus are allocated to all QSEs with schedules that impact congested CSCs. The QSE whose schedules aggravate the zonal congestion would be charged at a shadow price of the zonal congestion. However schedules of QSEs that contribute to resolving the zonal congestion are paid at the shadow price in proportion to their scheduled counter flow.

ERCOT's forward market includes both the bilateral market, and a market for transmission congestion rights (TCR). TCRs are used by market participants to hedge against the costs of resolving zonal congestion. A TCR is essentially a financial right on a zonal congestion path for a specific hour, where the TCR holder would have the right to receive compensation equal to the shadow price of zonal congestion on that path.[19]

In 2003, the PUCT ordered ERCOT to develop a nodal wholesale market design which would potentially deliver the benefits of improved price signals, improved dispatch efficiencies, and direct assignment of local congestion. There are plans to implement this design by 2010. Currently existing congestion management zones will be replaced with over 4,000 nodes over the grid. As part of the implementation of the nodal design, there are plans to implement a day ahead energy market to allow greater price certainty and co-optimize the AS and energy market (currently the AS market in ERCOT is a day ahead market).

Market Fundamentals

<u>Prices</u>

As noted, Texas is primarily an imbalance market and the majority of trade occurs via bilateral deals. Nonetheless, there has been considerable concern over spot market prices, the influence of market power and distortions created by congestion, for example.

The Public Utilities Commission of Texas (PUCT) approved an offer cap of $1,000/MWh in 2001. In May 2003, after experiencing 'hockey-stick' bidding (physical or economic

[19] Yu., J., Teng, S., Mickey, J. Evolution of ERCOT Market, IEEE/PES Transmission and Distribution Conference & Exhibition: Asia and Pacific, 2005.

withholding, resulting in small volumes offered at high prices) resulting in extreme market prices, the PUCT ordered ERCOT to implement a mitigation procedure called the Modified Competitive Solution Method (MCSM), which would limit the impact of ‘hockey-stick’ bidding. In addition, PUCT ordered ERCOT to implement a ‘sunshine’ policy, revealing the identity of any supplier that submitted a balancing energy bid greater than $900 whenever the marginal clearing price for energy (MCPE) exceeded $900.

The MCSM was terminated in 2006, as it resulted in unpredictable adjustments in prices, undermining the incentive of high prices in the balancing energy market. The MCSM was replaced with a new approach to market power mitigation and resource adequacy, including: increasing the offer cap, publishing resource specific offers, a scarcity pricing mechanism, the idea of ‘small fish swim free’,[20] and a voluntary mitigation plan. With the new approach to addressing resource adequacy and market power mitigation, the PUCT relaxed the $1,000/MWh offer cap, to be raised in 3 successive stages:

- March 1st, 2007: $1,500/MWh
- March 1st, 2008: $2,250/MWh
- 2 months after nodal market redesign: $3,000/MWh

Although the offer cap is currently set at $2,250 per the schedule above, this does not represent the highest possible price in the market. The shadow price is defined as “the cost of an operation to effect a one MW change in a constraint.”[21] It is used in settlement to directly assign costs of managing zonal congestion to QSE’s. The QSE whose schedules aggravate the zonal congestion would be charged at a shadow price of the zonal congestion. However schedules of QSEs that contribute to resolving the zonal congestion are paid at the shadow price in proportion to their scheduled counter flow. When there are two or more CSCs occurring at the same time, MCPEs may be at levels higher than the system-wide offer cap, or lower than the offer floor. The current shadow price cap is set at $5,000/MWh as of June 18th, 2008 and it is the highest allowable offer price to relieve congestion.

ERCOT has modeled its scarcity pricing mechanism and offer cap after the Australian market. The cap in Australia is significantly higher ($10,000 AUD) than that of ERCOT, since the ratio of all-time peak demand to average summer peak demand in ERCOT is lower than that of Australia.[22] This appears to suggest that the PUCT believed that the potential for extreme electricity demand during short-lived heat waves requires a higher price cap to allow generation capacity to recover its fixed costs in shorter periods.

The PUCT determined that there should be increased disclosure of information to the market due to the increase in offer caps. The information disclosure schedule is being

[20] In Texas it is illegal for an entity that has market power to withhold production. If an entity holds less than 5% of the total installed capacity in ERCOT, it is thought to not hold market power (a small fish) and thus would not be prosecuted if it withholds capacity from the market.

[21] ERCOT Protocols, Section 2: Definitions and Acronyms

[22] Public Utilities Commission of Texas, Project No. 31972 Order, August 2006, pages 42, 68 and 123. Viewed at http://www.puc.state.tx.us/rules/rulemake/31972/31972adt.pdf.

linked to the schedule for increases to the offer cap, emphasizing that these two issues are interrelated. The aim of the increase in information disclosure is to ensure that there is transparency in the marketplace so that the market operates in a competitive manner.

The scarcity pricing mechanism (SPM) is based on the Australian model,[23] intending to have higher offer caps to ensure resource adequacy, while mitigating the risk of excessive wealth transfer from load to generation when reserve margins are thin. The SPM is a backstop mechanism that will trigger the lowering of the offer cap for the remainder of a calendar year if the annual "Peaker Net Margin" (the profits of a peaker with a 10 MM Btu/MWh heat rate) is greater than $175,000/MW. If this threshold is exceeded, the offer cap is reduced to a level of $500/MWh (denoted as the low cap (LCAP). Spot market prices for the last 3 years are presented in Table 12.

Table 12 - ERCOT Prices

2003	<50	50 to 150	150 to 500	500 to 1000	>1000	Avg	Minimum	Maximum
Houston	83.4%	15.1%	1.5%	0.1%	0.0%	$39.82	($1,000.00)	$990.01
North	83.8%	14.5%	1.6%	0.1%	0.0%	$40.01	($1,000.00)	$999.00
South	85.3%	13.3%	1.3%	0.1%	0.0%	$38.42	($1,000.00)	$990.01
West	84.0%	14.3%	1.6%	0.1%	0.0%	$39.80	($1,000.00)	$990.01
2004								
Northeast	72.7%	26.6%	0.7%	0.0%	0.0%	$41.68	($2,240.71)	$463.19
Houston	72.0%	27.3%	0.7%	0.0%	0.0%	$42.25	($872.20)	$504.99
North	72.2%	27.1%	0.7%	0.0%	0.0%	$42.25	($579.17)	$525.36
South	73.7%	25.7%	0.6%	0.0%	0.0%	$41.32	($579.17)	$497.33
West	72.4%	26.9%	0.7%	0.0%	0.0%	$41.79	($1,000.00)	$456.25
2005								
Northeast	43.3%	52.0%	4.5%	0.2%	0.0%	$65.71	($298.63)	$1,030.00
Houston	42.6%	52.4%	4.7%	0.3%	0.0%	$67.28	($299.01)	$1,713.92
North	43.4%	51.6%	4.7%	0.3%	0.0%	$66.36	($299.00)	$999.50
South	44.1%	52.2%	3.6%	0.1%	0.0%	$63.38	($299.01)	$1,048.03
West	42.9%	52.2%	4.7%	0.2%	0.0%	$66.38	($299.00)	$2,263.85
2006								
Northeast	60.6%	37.6%	1.7%	0.1%	0.0%	$ 50.79	($971.02)	$1,045.85
Houston	58.5%	39.6%	1.8%	0.1%	0.0%	$ 52.04	($950.01)	$1,237.88
North	60.1%	38.1%	1.7%	0.1%	0.0%	$ 51.45	($950.01)	$1,035.85
South	62.0%	36.2%	1.8%	0.1%	0.0%	$ 50.12	($950.01)	$1,000.00
West	59.8%	38.4%	1.7%	0.1%	0.0%	$ 51.36	($950.01)	$1,002.85
2007								
Houston	52.1%	46.7%	0.7%	0.4%	0.1%	$ 53.80	($999.01)	$1,500.00
North	54.0%	44.9%	0.7%	0.3%	0.1%	$ 52.40	($999.01)	$1,583.26
South	53.2%	45.7%	0.6%	0.4%	0.1%	$ 52.72	($999.01)	$1,500.00
West	54.0%	44.6%	0.9%	0.4%	0.1%	$ 52.22	($999.01)	$1,533.51
2008								
Houston	42.1%	54.5%	2.6%	0.2%	0.6%	$ 72.18	($1,536.25)	$3,805.72
North	44.3%	53.6%	1.8%	0.1%	0.2%	$ 63.29	($999.01)	$2,382.51
South	42.4%	54.0%	2.9%	0.2%	0.5%	$ 72.82	($2,292.81)	$4,514.68
West	50.8%	46.6%	2.3%	0.2%	0.2%	$ 53.34	($1,981.81)	$2,320.68

Average prices in Texas are somewhat lower than those in Alberta, and the incidence of very high prices (>$500/MWh) is also lower in Texas than in Alberta. Prices in Texas

[23] In Australia, if the 7 day rolling sum of prices exceeds the Cumulative Price Threshold (CPT) of $150,000/MWh AUD, the price cap is lowered to $300/MWh AUD.

have exceeded $500/MWh less than 1% of the time over the past 6 years, despite a reserve margin that reached as low as 13.3% in 2006 (see Table 12). The incidence of prices in excess of $500/MWh in Alberta has been as low as 0.2% (in 2004 when the reserve margin was about 33%) and as high as nearly 3% (2008). The results suggest that Alberta prices have much more upward price volatility even with a nominally higher reserve margin.

<u>Generation Supply and Demand Growth</u>

Demand growth in ERCOT has basically been flat over the past 6 years, both in terms of average demand and peak demand. Nonetheless, the reserve margin in ERCOT has fallen quite substantially during the period, from near 30% in 2004 to a low of 13% in 2006. The reserve margin was about 17% for 2008 as significant generation additions of over 6000 MW offset the retirements taking place.

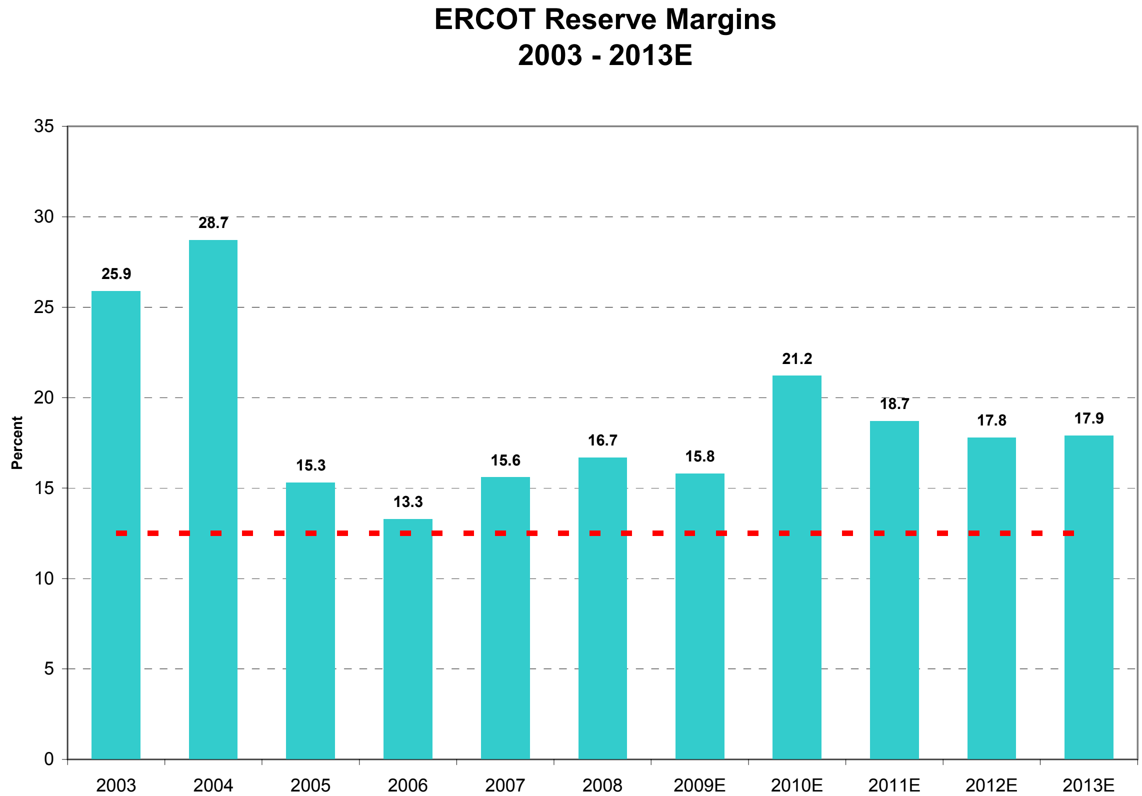
Table 13 - ERCOT Supply and Demand Statistics

Year	Peak Demand	Average Demand	Peak Demand Growth	Average Demand Growth	Load Factor	Generation Additions (GW)	Reserve Margin	Total Resources (GW)
2003	60,503	34,588	NA	NA	57%	4.9	26%	76.2
2004	58,589	33,076	-3.2%	-4.4%	56%	2.8	29%	75.4
2005	59,957	34,363	2.3%	3.9%	57%	1.4	15%	69.1
2006	63,056	35,496	5.2%	3.3%	56%	0.8	13%	71.4
2007	62,101	35,117	-1.5%	-1.1%	57%	2.3	16%	71.8
2008	62,124	35,813	0.0%	2.0%	58%	3.8	17%	72.5

Total retirements for the 2003 through 2008 timeframe amount to about 20 GW, while generation additions amount to about 16 GW. As such, generation retirements rather than demand growth drove the steep decline in the reserve margin shown in Figure 9.

It is also important to note that the load factor in ERCOT is relatively low at below 60%, which is in line with the Australian market, but well below the 80% load factor in Alberta. This likely plays into the price outcomes highlighted in the previous section, i.e. low prices occur in a large number of hours because there is excess supply that is in the market primarily to supply peak demands.

Figure 9 - ERCOT Generation Reserve Margins



ERCOT is also experiencing growth in wind generation on a large scale, as the market has added about 7,000 MW of wind capacity in the past 5 years. Total installed wind generation is currently just over 8,000 MW, which is more than 10% of the total installed capacity.

<u>Demand Side Behaviour</u>

The key source of demand side responsiveness in ERCOT is the reserves market, although there is also a substantial amount of load responsiveness from various retailer programs. In the reserves market, 1,960 MW of load is qualified to participate as LAAR (load acting as resource), but the hourly participation in the reserve market for load is capped at 1,150 MW (50% of the total requirement). Load regularly supplies its capped capacity in the reserves market.

In addition to the load participating in the reserve market, ERCOT also sees substantial participation from loads through arrangements with load serving entities (LSEs). About 1,000 MW of load participate under various programs, including load shifting through time of use metering, direct load control loads in response to price events, and peak load reductions on system peak days in order to reduce transmission demand charges.

Load response beyond load participation in the reserve market appears to be driven by LSEs. LSEs can financially benefit from encouraging loads to curtail when market prices are high because LSEs settle financially against the hourly market price based on their pre-set schedule. In effect, if the market prices are high and the LSE curtails a load, the power that would have been consumed is sold back into the spot market at a high price.

The barriers to greater demand responsiveness identified in Texas appear to be structural as opposed to a lack of financial incentive, i.e. price cap issues. The lack of advance notice for price events and lack of price certainty (ex poste pricing) were identified by ERCOT survey as issues standing in the way of further demand response.[24]

Conclusions

The overall market design in ERCOT is much more complicated than the Alberta design due to the congestion pricing model. ERCOT also has a much different approach to scheduling in that the bilateral market schedules about 95% of dispatch decisions.

High prices in ERCOT have occurred at a generally lower rate than in Alberta since 2003, despite the fact that ERCOT has had generally lower reserve margins during this time. Both markets are relatively isolated, but the ERCOT market is 6 or 7 times larger than the Alberta market. The load factor in Alberta is also much higher, which means that load is at high levels relative to peak demand in a greater number of hours. These are likely factors behind the greater frequency of scarcity pricing in Alberta, as was the case in Australia.

Demand responsiveness in ERCOT appears to be more advanced than it is in Alberta, but market structure is likely a key reason behind the responsiveness rather than the absolute level of the price cap. ERCOT's LSEs are incented to introduce programs that encourage price responsive load due to the market rules that require day ahead scheduling. Loads also participate very actively in the reserves market and often account for 50% of total reserves, which is higher than Alberta load's participation rate in the reserves market.

Netherlands

The Dutch electricity market is a deregulated market that serves the entire country and exchanges significant amounts of power with neighboring countries as well. The market began to de-regulate in 1998 with the establishment of DTe (the regulator) and TenneT (the transmission system operator). The retail market underwent a staged opening, with large customers gaining choice in 1998, and the smallest customers gaining choice in 2004. The current market structure has several vertically integrated generation companies that supply end users with power and own the distribution level transmission.

Netherlands has what amounts to a two part market, with a firm forward market combined with a real-time balancing market. The forward market is used to schedule flows over the interconnections, as well as trades between market participants. The overarching design principle is that participants should balance their schedules prior to real-time, and the balancing market is used to correct small imbalances that are unavoidable due to forced outages and fluctuations in demand.

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[24] http://www.goodcompanyassociates.com/files/manager/demand_response_in_ercot__paul_wattles.pdf

Programme Responsible Parties (PRPs) are generators, loads and retailers that participate in the Dutch wholesale energy market. PRPs are obligated to submit schedules prior to the real-time operation of the system, known as Energy Programmes. E Programmes can be altered up until one hour prior to delivery, and participants are financially responsible for the E Programme. In practice, this means that PRPs settle any imbalance relative to their E Programme at the imbalance price, regardless of what caused the imbalance to occur.

A key characteristic of the Dutch market is the degree of interconnectedness it has with neighboring European markets. Netherlands is connected to Germany, Belgium, and Norway. In total, these interconnections allow imports of about 4500 MW. An additional interconnection with Germany is currently under construction, which will bring the total connections between Germany and Netherlands to 4 lines.

An interconnection with the UK is currently under construction, and is planned for completion in 2010. It will initially have a capacity of 1000 MW, but there are already plans to expand it to 2000 MW shortly after it is completed. An interconnection with Denmark is also being explored. In total, TenneT aims to have interconnection capacity equal to 40% of its total generation capacity, which would amount to interconnection capacity of 8500 MW.

Market Fundamentals

Prices

The spot market in the Netherlands is a balancing mechanism that combines regulating and reserve power to balance the system. Participants in the market are required to make any spare capacity available to the imbalance market, somewhat akin to the must offer must comply requirement in Alberta. Offers into the spot market are two sided; offers to produce less or consume more, and offers to produce more or consume less.

Spot market volumes in the Netherlands are generally quite small due to the market design. Typically, 1.5% to 3% of volumes are traded in the spot market, and this appears to include volumes that would be akin to regulating reserve volumes in the Alberta market design. Notably, volumes that trade in the spot market are both positive and negative, and the typical range is +/- 400 MW.

The spot market for imbalance energy is best described as a clearing price market with the same price often holding for injections and withdrawals. Under most market conditions, as defined by the regulating state, the price for power is the same for those injecting and withdrawing power. However, in 10% to 20% of the year, there is a differential price where power is sold more cheaply than it can be purchased (regulating state 2).

Table 14 shows that the most common regulating state is -1, which means that market participants have overscheduled generation in the day-ahead and intra-day markets, and the balancing market must deal with the surplus. When the market is in surplus, the imbalance price is typically set at the dispatch down price for energy reductions, which is generally much lower than the dispatch up price for energy increases.

The table also provides information about emergency energy situations. These represent settlement intervals (15 minute periods) in which TenneT has had to use emergency generating capacity. This capacity is somewhat akin to power that the

AESO would have access to if it signed contracts under the long-term adequacy rules. TenneT has contracts with capacity that it prices into the market at 10% higher than the highest competitive offer, and therefore this capacity serves as emergency backup which has been utilized in 10 to 20 hours per year in recent years.

The price cap in the spot market is notionally set at €100,000[25], although as seen in the table the highest price actually realized between 2006 and 2008 was €1,200.19. The market design in the Netherlands discourages extremely high balancing offers because PRPs are responsible for their imbalances at the spot price. If a PRP submits a very high offer price and unexpectedly becomes short, it must purchase power to make up its imbalance. Since imbalances are somewhat unpredictable, PRPs have not entered offers anywhere near the price cap in order to mitigate their risk of an imbalance.

Table 14 – Netherlands Spot Market Statistics

2006	Take from system			Feed into system			System Status	
Regulating State	Max	Min	Avg	Max	Min	Avg	% of reg. state	Emergency Energy Count
-1	€ 87.14	€ 200.00-	€ 12.60	€ 87.14	€ 200.00-	€ 12.60	47%	5
0	€ 52.00	€ 14.66	€ 26.05	€ 52.00	€ 14.66	€ 26.05	0%	0
1	€ 1,200.19	€ 24.96	€ 108.35	€ 1,200.19	€ 24.96	€ 108.35	39%	57
2	€ 960.00	€ 23.20	€ 78.47	€ 87.67	€ 200.00-	€ 28.16	14%	0
2007	Take from system			Feed into system				
-1	€ 200.19	€ 200.00-	€ 13.76	€ 200.19	€ 200.00-	€ 13.76	50%	4
0	€ 65.73	€ 14.60	€ 24.64	€ 65.73	€ 14.60	€ 24.64	0%	0
1	€ 977.19	€ 0.00	€ 74.27	€ 977.19	€ 0.00	€ 74.27	39%	80
2	€ 925.19	€ 0.00	€ 49.08	€ 150.19	€ 200.00-	€ 22.86	11%	2
2008	Take from system			Feed into system				
-1	€ 181.19	€ 200.00-	€ 32.48	€ 181.19	€ 200.00-	€ 32.48	44%	3
0	€ 63.88	€ 38.87	€ 53.58	€ 63.88	€ 38.87	€ 53.58	0%	0
1	€ 1,062.81	€ 0.00	€ 121.01	€ 1,062.81	€ 0.00	€ 121.01	38%	40
2	€ 678.37	€ 0.00	€ 92.84	€ 178.19	€ 200.00-	€ 41.07	18%	1

The primary day-ahead market is the Amsterdam Power Exchange, or the APX. The APX is owned by TenneT, the transmission system operator (TSO) in Netherlands that also owns and operates the spot market. The price cap in the APX market is €3000, and was set at this level to allow better integration with interconnected markets where the price cap was €3000.

Demand Side Behaviour

Due to the design of the Dutch market, load is fully engaged in the forward market because PRPs must balance their expected schedule prior to real-time. This requires that any parties expecting to be short of power purchase it prior to the real-time imbalance market.

In terms of behaviour in the real-time spot market, about 1000 MW of load actively participates in the Netherlands.[26] Of this, about 650 MW is contracted capacity, either

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[25] Van der Veen, Balancing market performance in a decentralized electricity system in the Netherlands, 2007.

[26] http://www.etso-net.org/upload/documents/Demand%20Side%20Response%20Explanatory%20Note.pdf, pages 10 to 11.

with a retailer or with the grid operator, TenneT. TenneT contracts about 300 MW of capacity as emergency power to be dispatched down when there is insufficient generation to meet demand, as per the discussion in the pricing section. The remaining 350 MW is contracted by PRPs in order to manage their exposure in the imbalance market. The remaining 350 MW is self-dispatched in response to price signals. The break-even point for the majority of price responsive load is reported to be between €300 and €500.

Conclusions

Overall, the Netherlands market design is quite different from the Alberta design, with the key change being the addition of a binding forward market. Additionally, the balancing market in the Netherlands does not really equate to the spot value of energy. Rather, it represents a mix between regulating services and the spot value of energy, meaning that the spot price does not typically converge with forward prices.

The price levels in the imbalance market range quite widely depending on what state the market is in, i.e. short power, long power or roughly balanced. The price cap in the imbalance market has not been a binding cap over the past 3 years. The highest price in the imbalance market has been well below the cap, and has not even approached the $3000/MWh cap in the forward market.

The requirement to operate balanced schedules has resulted in very small volumes traded in the imbalance market, and the tendency has been for PRPs to slightly over schedule power such that the imbalance market often must shed excess power. The market design has encouraged vertical integration as most PRPs have sufficient or near sufficient generation capacity to meet their load obligations.

In terms of resource adequacy, the system relies on emergency power purchased outside the market in about 40 hours per year. This is quite similar to the amount of time Alberta operates at the price cap in recent years.

Netherlands has been a large net importer since it deregulated its market due to its higher embedded cost of generation. The Dutch interconnections are generally to lower priced markets and the result is that power typically flows into the Netherlands. However, sufficient interconnections have now been developed that the interconnected markets typically have similar clearing prices.

On the whole, the price cap does not appear to be a substantial issue in the Dutch market. In the forward market, the cap was set at a level to align with the interconnected markets, and in the spot market, the price cap has never been reached based on the information available to the AESO. The market design places risk on participants that price imbalance energy at very high levels, dramatically reducing the importance of the cap.

OPP 801 Steps

Supply Shortfall Management Instructions			Return to Normal Instructions	
1.	↓	When the short term adequacy program issues an alarm the SC will perform a short term adequacy assessment in accordance with OPP 705.	↑	Take no action in this step.
2.	↓	Perform the planning steps as identified in Section 5.1 when anticipating a supply shortfall.	↑	If planning steps were performed, but the step in this table was not reached that required this action be taken, then undo the planning action that was taken by performing any of the following as required: • Permit transmission maintenance. • Cancel public appeal via Operations on-call person. • Restore DOS 1 hour loads. • Repost export ATC to normal levels. • Notify VRC, BCTC and SPC that an Energy Emergency Alert 1 was not reached. • Dispatch on VLCP loads.
3.	↓	Use all the resources in the energy market merit order to maintain the balance between supply and demand and dispatch assets offered into the ancillary service merit order to provide the required amount of operating reserve.	↑	Resume normal energy market dispatch.
4.	↓	When all resources in the energy market merit order have been dispatched notify the AESO personnel in accordance with Table 1 in OPP 1303 (confidential)	↑	Notify the AESO personnel that were previously notified that the supply shortfall event has ended and issue the following message in ADAMS to all participants and enter it into the SC Shift Log and select the post to web option: “The supply shortfall event is no longer in effect and normal operation has resumed.”
5.	↓	Maximize the posted import ATC limit by confirming it is based on the lesser of: a. The import limit specified in OPP 304. b. The total amount of Load Shed Service (LSS) currently available. Refer to Table 1 in OPP 312.	↑	Take no action in this step.

		Notify BCTC if the posted import ATC limit is changed.		
6.	↓	Reduce export ATC to zero on the interconnections with BC and Saskatchewan. If possible, re-post the export ATC 1 hour in advance.	↑	Post BCTC and SaskPower import and export ATC to normal levels.
7.	↓	Curtail 1-hour demand opportunity service (DOS) loads. These loads will take up to 1 hour to curtail. Use the list in the DOS program and follow procedures in OPP 901.	↑	Restore DOS 1-hour loads. Use the list in the DOS program and follow procedures in OPP 901.
8.	↓	Curtail 7-minute DOS loads. Use the list in the DOS program and follow procedures in OPP 901.	↑	Restore DOS 7-minute loads. Use the list in the DOS program and follow procedures in OPP 901.
9.	↓	Curtail DOS standard loads. Use the list in the DOS program and follow procedures in OPP 901.	↑	Restore DOS standard loads. Use the list in the DOS program and follow procedures in OPP 901.
10.	↓	Cancel transmission maintenance as necessary to remove generation constraints or increase import ATC on the Alberta-BC and/or Alberta-Saskatchewan interconnection(s) by issuing directives to TFOs and request BCTC and/or SPC to cancel transmission maintenance on their respective systems that reduce import ATC to Alberta.	↑	Permit transmission maintenance to continue that was previously cancelled to remove generation constraints or increase import ATC.
11.	↓	If there are non-dispatched external reserves (ER) on the BC interconnection, then maximize the use of external reserves in accordance with the following formula: ER ≤ CRO – Net Imports from BC + Armed ILRAS + LSS where: • ER is the dispatched amount (MW) of external reserves. • CRO is the contingency reserve obligation for the purpose of NWPP reserve sharing group (refer to OPP 405). • LSS is the total of the contracted LSS loads that are on-line. • Armed ILRAS is the amount (MW) of load armed for ILRAS as per OPP 312 if planning step 4 in Section 5.1 was performed to arm ILRAS, otherwise use 0 MW.	↑	Dispatch to the normal level of external supplemental and external spinning reserves, refer to OPP 403.

12.	↓	If the duration of the supply shortfall is expected to be less than 1 hour, then issue directives for dispatched contingency reserves that are in excess of the contingency reserve requirement.	↑	Cancel directives issued for contingency reserves and return to normal dispatch priorities in the ancillary service merit order.
13.	↓	If the duration of the supply shortfall is expected to be less than 1 hour, then dispatch up supplemental loads with standby and backstop supply types that are offered in the ancillary service merit order and repeat step 12 if dispatches are made.	↑	Take no action in this step.
14.	↓	Perform the following steps: a. Request the VRC to declare an Energy Emergency Alert 1 for the AIES. b. If the VRC agrees to the request, then follow procedures in OPP 802 to issue an Energy Emergency Alert 1 and make the required notifications. c. Request the AESO operations person on call to notify Stakeholder Relations and Communications in accordance with Table 1 in OPP 1303 (confidential).	↑	Perform the following steps: a. Request the VRC to downgrade the alert for the AIES to an Energy Emergency Alert 0. b. If the VRC agrees to the request, then follow procedures in OPP 802 to issue an Energy Emergency Alert 0 and make the required notifications.
15.	↓	Issue the following message in ADAMS to all participants: "A supply shortfall is in effect. Please confirm must offer volumes of available capability are accurate." Put a comment in the Shift Log in the Additional Information field (to prevent the comment from being posted to the web), stating a request was issued to confirm must offer volumes of available capability are accurate.	↑	Take no action in this step.
16.	↓	Take no action in this step. **Note**: If planning step 4 in Section 5.1 was performed to arm ILRAS, then this is the step that was anticipated to be reached to require the use of ILRAS to increase import ATC on the AB-BC interconnection.	↑	Cancel dispatch for arming ILRAS and provide the time when the ILRAS loads are to be disarmed. Determine and post the AB-BC import ATC with only available LSS and put a 0 MW override on the ILRAS value on display #6975
17.	↓	Consider a public appeal if conditions warrant it (step 5 of Section 5.1).	↑	If a public appeal was made, then request the AESO operations on-call person to terminate the public appeal to reduce energy demand.
18.	↓	Request the wire service providers (WSPs) identified in Table 2 (confidential) to institute a 3% distribution voltage reduction.	↑	Notify the WSPs identified in Table 2 (confidential) that the 3% reduction in distribution voltage is no longer required.

19.	↓	Call the plant operators for the generators listed in Table 3 (confidential) in sequential order, to give permission to supply additional MWs up to the gross MW level identified in Table 3. If the SC assesses that system conditions do not permit the use of MWs above MAM from an asset, then the SC will skip the asset and go to the next asset in the list. Use the following script: "This is "*your name*", System Controller from the Alberta Electric System Operator. The AIES is in a supply shortfall and "*name & number of generator*" is permitted to supply additional energy up to a gross output level of "*XXX MWs*". Supply of this additional energy is at your discretion, and does not require an energy market restatement or an energy market dispatch."	↑	Call the plant operator(s) that were previously permitted to supply additional MWs up to the gross MW level identified in Table 3 (confidential). Make the calls in the reverse order as in Table 3 and use the following script: "This is "your name", System Controller from the Alberta Electric System Operator. T*he AIES is* returning to normal operation. You are no longer permitted to supply additional energy above your energy market dispatch. "Name & number of generator" is required to return to the energy market dispatch level."
20.	↓	Issue ancillary service directives for supplemental and excess spinning reserves, except for external reserves.	↑	Cancel ancillary service directives for supplemental and excess spinning reserves.
21.	↓	If ILRAS load has not been armed for the current hour, then arm additional ILRAS load to increase Alberta-BC import ATC for the current hour, refer to step 4 in Section 5.1. Post the revised AB-BC import ATC.	↑	
22.	↓	If import ATC is available permit mid-hour interchange transactions with interruptible energy and or interruptible transmission service from importers on the BC and Saskatchewan interconnections up to the posted import ATC limit and issue the following message in ADAMS to all participants: "The AESO will accept mid-hour interchange transactions with interruptible energy and or interruptible transmission service from importers up to the import ATC limit. Valid e-tags submitted for import energy that have not been dispatched will be approved by the SC up to the ATC limit."	↑	Terminate interruptible imports on the Alberta-BC and Alberta-Saskatchewan interconnections and issue the following message in ADAMS to all participants: "Interchange transactions with interruptible energy or interruptible transmission service from importers will no longer be accepted." As applicable, put a comment in the shift log in the Additional Information field (to prevent the comment from being posted to the web), stating the interchange transactions with interruptible energy or interruptible transmission service from Importers has been terminated.
23.	↓	Request the plant or generation operator identified in Table 4 (confidential) to reduce non-essential	↑	Restore non-essential station service loads as identified in Table 4 (confidential).

		station service loads.		
24.	↓	Dispatch off the AESO Voluntary Load Curtailment Program (VLCP) loads as identified in Table 5 (confidential). At least 1 hour notice is required. Log this in the shift log, but do not post it on the web.	↑	Dispatch on the AESO VLCP loads as identified in Table 5 (confidential). Log this in the shift log, but do not post it on the web.
25.	↓	If ATC is constrained down because of the lack of LSS and ILRAS load offers, then disregard this constraint and increase the posted Alberta-BC interconnection import ATC up to the limit as if all available LSS and ILRAS loads are in service. Refer to OPP 304 and OPP 312. Notify BCTC if there is a change to the posted import ATC limit. If additional ATC is available, then issue the following message in ADAMS to all participants: "Import ATC on the Alberta-BC interconnection has been increased for the current hour. Valid e-tags submitted for import energy that have not been dispatched will be approved by the SC up to the ATC limit."	↑	Post the Alberta-BC interconnection import ATC to the limit that reflects the available LSS and ILRAS loads.
26.	↓	Issue directives to curtail all remaining LSS loads. Check the telemetered LSS volumes on Ranger display 6975/HIMP and curtail LSS load if the volume is non-zero. Refer to confidential appendix in OPP 312 for LSS contact information.	↑	Cancel load curtailments directives issued to LSS loads.
27.	↓	Dispatch on external supplemental and external spinning reserves with standby and backstop supply types that are offered into the ancillary service merit order, to an amount no greater than the difference between the net interchange schedule on the Alberta-BC interconnection and the posted ATC import limit.	↑	Dispatch off external supplemental and excess external spinning reserves with standby and backstop supply types.
28.	↓	If external supplemental and spinning reserves were dispatched, then issue an ancillary service directive(s) for external supplemental and excess external spinning reserves to increase the net interchange schedule on the Alberta-BC interconnection to a level not greater than the posted import ATC limit.	↑	Cancel the ancillary service directive for external spinning and external supplemental reserves.
29.	↓	Issue ancillary service directives for spinning reserves. a. Request the VRC to declare an Energy Emergency Alert 2 for the	↑	Cancel the ancillary service directive for spinning reserves. a. Request the VRC to downgrade the alert for the AIES to an Energy

		Alberta balancing authority. b. If the VRC agrees to the request, then follow procedures in OPP 802 to issue an Energy Emergency Alert 2 and make the required notifications.		Emergency Alert 1. b. If the VRC agrees to the request, then follow procedures in OPP 802 to issue an Energy Emergency Alert 1 and make the required notifications.
30.	↓	If there is available capacity (i.e., surplus ATC) on the interconnections, request emergency energy from BCTC and SaskPower. Follow the procedures in OPP 803 and OPP 807.	↑	Terminate emergency energy from SaskPower and BCTC.
31.	↓	Issue a firm load directive to curtail load. Refer to OPP 802. a. Request the VRC to declare an Energy Emergency Alert 3 for the Alberta balancing authority. b. If the VRC agrees to the request, then follow procedures in OPP 802 to issue an Energy Emergency Alert 3 and make the required notifications. c. If 100 MW or more of firm load was curtailed, complete and submit a NERC Preliminary Disturbance Report within 24 hours.	↑	Restore firm load by following the procedures in OPP 802. a. Request the VRC to downgrade the alert for the AIES to an Energy Emergency Alert 2. b. If the VRC agrees to the request, then follow procedures in OPP 802 to issue an Energy Emergency Alert 2 and make the required notifications.