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PROPOSED RULE CHANGE

TO

ENHANCE GENERATOR COMPETITION OUTCOMES

DURING HIGH DEMAND PERIODS IN THE NEM

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The views expressed in this document do not necessarily reflect the views of the Consumer Advocacy Panel or the Australian Energy Market Commission.

The content and conclusions reached in this proposal are entirely the work of the MEU and its consultants.

All of the NEM data figures were produced out of NEMReview. Unless otherwise attributed, figures in the report are from NEMReview

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The Proposed Rule Change

This rule change proposal has the following elements:

- The dominant[1] generator(s) in each National Electricity Market (NEM) region is declared as a dominant generator(s).

- The declaration process will be conducted by the Australian Energy Regulator (AER), using criteria for assessing regional demand and other conditions under which the dominant generator(s) is able, at particular demand levels in a region, to set prices without any effective competition from other generators, or has the ability to manipulate prices and supply in a regional market to the extent that the actions of other generators have no ability to influence or establish the regional reference price.

- The dominant generator(s) in each region can submit bids at any price until a predetermined regional demand (assessed by the AER under the declaration process) is reached:

    - This predetermined regional demand level would be the same as that used in determining a dominant generator(s).
    - Above the predetermined regional demand level, the dominant generator(s) is constrained to bid up to a maximum price but will not have the ability to set prices during extreme demand conditions above this level. This rule change is written such that this maximum level should be the Administered Price Cap (currently $300/MWh)[2].

- All other competing generators in the region will be free to bid at any price level up to the market Maximum Price Cap.

- When the regional demand reaches or exceeds the value set by the AER in determining a dominant generator(s), the Australian Energy Market Operator (AEMO) shall "call" on the dominant generator to dispatch all of its available capacity at the maximum price set for a dominant generator(s).

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[1] Throughout this proposal, the term "dominant generator" has been used as describing a generator which has the ability to exercise market power. In the US and in other jurisdictions, the term "pivotal generator or supplier" is also used

[2] The Administered Price Cap is seen as an appropriate level as this price is seen by the AEMC as providing a revenue in excess of the LRMC for almost all generation operating in the NEM. Section 8.2.1.2 provides more detail on why the MEU has selected this level.

- The dominant generator(s) in each region is prohibited from exercising economic or physical withdrawal of capacity when it has been declared by the AER to have market power in the region and the predetermined regional demand has been exceeded.

- The “dominant generator(s)” will receive the regional reference price for its output set by it and competing generators.

- As all other generators would be dispatched in accordance with their bids and offers, market integrity is maintained except for constraining the pricing of only the dominant generator(s) when it is not possible for it to be constrained by competing generation.

- When the regional demand exceeds the level assessed by the AER for identifying a dominant generator(s), and if the spot regional reference price exceeds the maximum price allowed for the dominant generator, then all generators (including the dominant generator) will receive the spot regional reference price, effectively retaining the integrity of the market structure.

- The proposed rule change will enhance economically efficient market outcomes during high demand periods.

The NEO and the proposed rule change

The National Electricity Law (NEL) states that the National Electricity Objective (NEO) is:

> *"to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –*
> *(a) price, quality, safety, reliability and security of supply of electricity;*
> *(b) the reliability, safety and security of the national electricity system."*

The NEO is written in terms of the needs of consumers to have a long term viable least cost supply of electricity. In the Second Reading Speech when the NEO was introduced in the SA Parliament, the Hon. J.D. Hill, for the Hon. P.F. Conlon (Minister for Energy) stated[3] in relation to the NEO:

> "The market objective is an economic concept and should be interpreted as such. For example, investment in and use of electricity services will be efficient when services are supplied in the long run at least cost, resources including infrastructure are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs and productive opportunities.
>
> The long term interest of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the National Electricity Market is efficient in an economic sense the long term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised
>
> ... Applying an objective of economic efficiency recognises that, in a general sense, the national electricity market should be competitive..."

The clear import of the objective is that the "long term interests of consumers" will be achieved by a **competitive** national electricity market. In the second reading speech the Minister also notes (page 1452) that:

> "It is important to note that all participating jurisdictions remain committed to the goals expressed in the current market objectives set out in the old [National Electricity] Code, even though they are not expressly referred to in the new single market objective."

The first objective (clause 1.3(b)(1)) of the National Electricity Code is that:

[3] Hansard SA House of Assembly, Wednesday 9 February 2005, National Electricity (South Australia) (new National Electricity Law) Amendment Bill, page 1452

"... the [national electricity] market should be competitive;"

This requirement explicitly stated as carrying forward from the National Electricity Code replicates the requirements of the National Competition Policy. Implicitly it is recognised that the interests of consumers will be maximised if there is clear competition between providers of services.

Recognising the tension implicit between cost and reliability and security of supply, the NEO will be achieved if:

- The wholesale and retail electricity market is competitive, and
- There are incentives for new generation capacity to be provided to meet future consumer needs.

The National Electricity Rules (NER) provide the basis for achieving competition between generators by the operation of the wholesale electricity market which dispatches lowest priced generation ahead of higher priced generation. In theory the NEM rules are structured in a way that would result in the dispatch of generation following the relative short run marginal costs of each generator operating in the NEM[4].

The NER provides the incentive for avoiding future scarcity of supply by the setting of the market price cap (MPC) at a level that provides an incentive to build needed generation. The MPC is derived by assessing the price for electricity a generator would need if it were the last generator needed (often called the marginal generator) to operate for just a few hours each year. In theory, this marginal generator should be the only generator not subject to competition, as at lower regional demand levels than the demand level at which the marginal generator is required, every generator has at least one other generator to compete against it.

Essentially, this proposed rule change applies surrogate competition to every generator (other than the marginal generator) where, due to the structure of the NEM, some generators have the ability to set regional prices in the absence of any competition.

Setting the MPC at such a high level also provides an incentive for a generator which has, at other times, the power to set the regional price for electricity, to use this power to increase its revenue, especially at demand levels when there is no effective competition from other generators. As the NEO is based on the principle of competition providing the least cost of electricity for consumers, it therefore is not intended to allow any generator (other than the marginal generator) being able to unilaterally set the price in the wholesale market. Implicitly, the incentives in the NER for new generation are there to address

[4] This concept is intended to replicate the dispatch of generation in a traditional fully vertically integrated electricity system and is more fully developed in section 3

scarcity of future supply, and not to provide a benefit from exercise of market power.

This proposed rule change does not alter the concepts embedded in the NER to provide competition between generators in order to provide the least cost for supply and, in fact, provides a basis under which this would occur for more of the time. The propose rule change does not change the incentives for building new generation to overcome future scarcity,

This proposed rule change is to prevent a generator from exercising its market power when there is no scarcity of supply and there is no effective competition from other generators, but to concurrently maintain the same level of investment signal for new generation. Achievement of these two goals will enhance the ability of the rules to better meet the requirements of the NEO and the National Competition Policy.

Executive Summary for the reasons for a rule change

The exercise of generator market power in the NEM has been well documented by numerous analysts, including the Australian Competition and Consumer Commission (ACCC) and AER. In a report to the Council of Australian Governments (CoAG) by the Energy Reform Implementation Group (ERIG) in January 2007, the findings were that:

> "... in the NEM, there is some evidence of the on-going exercise of market power. This appears to be persistent, but intermittent. The magnitude of non-competitive outcomes appears to be such as to have a material adverse impact on the economic performance of the market. This appears to be most significant in New South Wales."(p. 71)

However, since 2006 when the ERIG report was written, the exercise of generator market power by dominant generators in the NEM has been more frequent and sustained, especially in some regions such as South Australia.

The economic consequences of such activities include:

- Incurring of substantial monetary and economic losses by major energy users exposed to the wholesale spot market ie a significant transfer of wealth from consumers to generators, causing a reduction in downstream investment.
- An increase in prices of retail contracts and a general raising of electricity prices
- Substantial increase in market risks, prudential requirements and hence costs, in making transactions in the NEM.
- Exiting of retailers unable to obtain hedge contracts to be competitive or to manage risks.
- Creation of barriers to new entrants in generation and retail.

The NEM is unique, compared with major overseas jurisdictions operating competitive electricity markets, in having only minimal provisions in the NER to prevent generators exercising their market power. The NER provisions, however, have no mitigating impact on preventing generators from exercising their market power, especially at times of high demand but where there is no scarcity of supply.

The NEL and NER clearly imply that competition issues in relation to the NEM, are sufficiently dealt with under the Trade Practices Act (TPA). The TPA has limitations in tackling the **outcomes** of the misuse of market power as its concentrates on ensuring there is strong competition as the fundamental approach to limit the outcomes of the misuse. However, where there is market power and it is misused, but not for a purpose proscribed under the TPA, there is no legal remedy for that misuse. This means there is no legal remedy for misuse of market power through strategic bidding to spike prices opportunistically to maximize revenue.

Consumers consider that the exercise of market power by dominant generators in a region needs to be constrained, and the Major Energy Users (MEU) makes this rule change proposal in order to minimise the exercise of generator market power.

To assess the effectiveness of the proposed rule, the MEU applied a test (see section 7.5) whereby the rule change elements proposed were superimposed on the South Australian (SA) regional spot market outcomes after Torrens Island Power Station (TIPS) commenced exercising its market power in 2007. The results showed that 2008 and 2009 spot prices after applying the price cap to TIPS were much more closely aligned to prices that applied between 2004 and 2006 before AGL Energy (AGL) acquired TIPS, but still in keeping with the long run marginal cost of generation in SA.

The rule change proposal will have other benefits:

- Allows the NEM market design to operate as intended – i.e. merit order dispatch of generation
- Reduces spot price volatility and hence market risks, costs, and prices
- With the greater certainty that spot prices reflect market fundamentals and are not created by the exercise of market power, the rule change will improve competitive market signals to new generation investment, and as such will

    - Improve liquidity in the contract market
    - Improve liquidity in the futures market

Notwithstanding the above benefits, there may be a concern that the rule change could reduce incentives for investment in generation. Analysis indicates that the very presence of an ability to manipulate the market price is not only anti-competitive but creates its own uncertainty – about whether:

- Change will occur to prevent further manipulation,
- The apparent market signals are a true reflection of the actuality of a properly operating market
- The dominant generator will exercise its market power or not, and when.
- The market will be sent into an administered price state because the cumulative price threshold (CPT) will be exceeded

This rule change proposal addresses the possible detriments to the market by the introduction of the rule, and concludes that the possible detriments are insignificant and manageable compared to the benefits that will flow in the NEM, for downstream investment and consumers in general, and, whilst unlikely to have any significant negative impact on investment in new generation, is likely to assist in this endeavour due to the greater certainty that market outcomes (as opposed to manipulated outcomes) that will result.

Throughout this proposed rule change, the MEU has used as examples of the exercise of generator market power, the South Australian region and TIPS and to a lesser extent, Macquarie Generation in NSW region. The reasons for this are as follows:

- The AER has specifically reported on the activities of these two power stations in their market assessments.
- The actions of TIPS and Macquarie have been clear examples of a base generator exercising its market power and, as such, have provided a very clear demonstration of the points needed to be made.
- Hydro Tasmania has undoubted market power in Tasmania and, as it has always had this, it is difficult to separate when Hydro used its market power for commercial gain, and when it has operated on the basis of scarcity of supply.
- Generation in Victoria and Queensland has not been identified (so far) as exercising market power to a significant extent, and a preliminary assessment by the MEU is that the largest generators in those regions do not have market power at less than the highest recorded regional demands, although in Victoria it is possible that Loy Yang A now has this power.

1. Introduction

1.1 Some history of market manipulation in electricity markets

It is well recognised that electricity markets, in particular, are susceptible to manipulation by generators such that the spot market prices do not reflect the marginal costs of generation. A classic experience of this was seen in California in 2000 – better known as the California Crisis.

In 2000, the wholesale electricity market in California was manipulated in such a way as to make the wholesale price of electricity reach very high levels. As a result of this activity, two of the electricity default retailers – Southern California Edison and Pacific Gas and Electric (PG&E) – were caught between fixed retail electricity tariffs and very high wholesale prices[5], faced bankruptcy and PG&E filed for protection under Chapter 11 laws.

The US Federal Energy Regulatory Commission (FERC) investigated the causes of the very high prices and identified that some generation plant owners and others had deliberately withheld plant to increase the wholesale price of electricity[6]. Whilst the impact on consumers was initially muted due to the retailers being required to supply at set prices, after the credit ratings of the two companies collapsed, the State of California had to step in and buy contracts at high prices, the costs of which were passed onto consumers.

As a result of this investigation, FERC introduced rules against market manipulation which apply to all competitive electricity markets in the US. These are encapsulated in six market behaviour rules[7]. Subsequently these have been made into formal rules following the principles of the Federal Power Act and the US Securities Exchange Act, to prohibit manipulation of energy markets[8].

In the UK, as a result of alleged market manipulation of the power transmission lines between Scotland and England (which are in effect a constrained interconnector), Parliament enacted legislation to empower the Secretary of State to introduce a Market Abuse Condition into generator licences under certain conditions[9].

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[5] It has been observed that, at the time, many of the retailers in California were not fully hedged for their power supplies and this could be seen to be a contributing factor to their financial exposure to the electricity market.
[6] See Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities Part I November 1, 2000, available at http://www.ferc.gov/industries/electric/indus-act/wec/rev-chron.asp#2002
[7] See appendix 3
[8] FERC, Docket No. RM06-3-000; Order No. 670, Prohibition of Energy Market Manipulation (Issued January 19, 2006)
[9] See appendix 4(b) which provides more details about these recent changes iun the UK electricity market.

The MEU considers that similar market manipulation has occurred in a number of regions in the National Electricity Market (NEM) in Australia (eg NSW, SA and Tasmania), but most obviously in the South Australian region since 2007, where spot prices (and subsequently retail contract prices) have increased by more than 50% due to Torrens Island Power Station (TIPS) withdrawing capacity or pricing the bulk of its capacity at the Market Price Cap (MPC) at times of high demand, causing the spot prices to approach the MPC[10].

Just as FERC introduced provisions to prevent market manipulation across the whole of the US as a result of the California experience and as the British Parliament has done in the UK, the MEU considers similar action is required in the NEM.

1.2 The history behind the MEU proposal

A key conclusion of the FERC staff report into the California crisis[11] was that:

> "Staff concludes that prices in the California spot markets were affected by economic withholding and inflated bidding. Staff finds this violated the antigaming provisions of the Cal ISO and Cal PX tariffs and recommends proceedings to require disgorgement of profits associated with these inflated prices. This investigation did not address physical withholding of generation, an issue the Commission is addressing separately."

This is the same issue that MEU sees applying in the NEM, especially in the SA region since 2007. The acquisition of TIPS by AGL in 2007 created a combination of the largest electricity retailer in the region with the largest (base load and intermediate (mid merit) load) generator. Appendix 5 provides a more detailed explanation of what occurred in SA and how this has resulted in the SA regional electricity price (in both the spot market and the contract market) increasing by some 50% and the exit of several retailers from the SA region.

There is no doubt that AGL has operated TIPS to maximise its revenue and appendix A5.3 details how AGL achieves this. When consumers asked AGL staff about the activities of TIPS, they were advised that AGL operated TIPS in accordance with the NER, and that they had an obligation to shareholders to use all legal means to maximise the profitability of the business. This response reflects the Corporations Law requirements on directors.

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[10] See for example, AER report on Spot prices greater than $5000/MWh South Australia: 5 - 17 March 2008 where the AER states "However, the report finds that bidding behaviour by AGL significantly contributed to the high priced events. On 5, 6, 7, 12 and 13 March, AGL was the only participant who offered significant amounts of capacity at over $5000/MWh. In fact, around 80 per cent of capacity at AGL's Torrens Island power station was priced above $5000/MWh".

[11] Final report on price manipulation in western markets fact-finding investigation of potential manipulation of electric and natural gas prices FERC Docket no. PA02-2-000 March 2003, page ES-2

The AER has been quite concerned about generators using their market power to increase the market prices. An early reference to this was in its State of the Energy Market 2008 and this continued into its State of the Energy Market 2009 where, on page 3, the AER observed:

> "Despite generally benign conditions, **concerns remain that some generators have been exercising market power in some regions**. The NEM was designed to minimise the risk of market power, through an interconnected transmission grid that allows competition between generators. **But there are circumstances in which baseload generators can price capacity at around the market cap and be certain of at least partial dispatch**. This behaviour is often more evident at times of peak demand, typically on days of extreme temperatures.
>
> The opportunities for market power are enhanced if transmission interconnector limits are reduced. Given the relatively inelastic demand for electricity and the high market price cap, **such circumstances can lead to significant opportunities for price manipulation**.
>
> The AER referred in previous *State of the Energy Market* reports to generators exercising market power in New South Wales in 2007 and in South Australia in 2008. These occurrences were reflected in significant price spikes (figure 1). While some price events relate to exogenous factors such as extreme weather, bushfires and unplanned infrastructure outages, **a number of spikes in the past two years coincided with strategic generator bidding.**
>
> There have been continuing concerns in South Australia, where spot prices in the past two years were significantly higher than in other mainland NEM regions. In the early months of 2009 South Australian spot prices exceeded $5000 per megawatt hour (MWh) on 27 occasions. **The bidding strategies of AGL Energy for its Torrens Island power station were a key contributing factor on most occasions.** The events typically occurred on days of extreme temperatures and demand, which created a tight supply – demand balance. Under these conditions, Torrens Island can bid a significant proportion of its capacity at around the market cap and be guaranteed at least partial dispatch.
>
> More recently, market bidding strategies emerged as a concern in Tasmania. In June 2009 the spot price in Tasmania exceeded $5000 per MWh on 13 occasions. The spikes were often driven by **Hydro Tasmania making sudden and repeated cuts in the output of its non-scheduled (mini hydro) generators, in conjunction with strategic bidding for the rest of its portfolio**. The strategy led to administered pricing being applied for four days in June — the first time for Tasmania." (Emphasis added)

The issue of "strategic bidding" by base load generators is a significant concern as it demonstrates that the basic assumption in the NEM that competition will constrain prices does not apply under certain circumstances which are unrelated to supply scarcity.

There is no doubt that AGL used its unique position as the dominant retailer in SA and owner of TIPS, to increase the spot price when it could. This directly caused financial loss to consumers operating in the spot market, and indirectly to all consumers operating with retail contracts because, as a result of the spot price movements, retail price offerings increased immediately by some 50% or more, with fewer retailers prepared to provide offers.

It is assumed that the misuse of market power is precluded by the Trades Practices Act (TPA) and there have been decisions using the TPA that have addressed the misuse of market power[12]. The electricity market rules require issues of competition to be addressed under the TPA[13] but sections 46, 47, 48, 49 and 50[14] of the TPA (which address the misuse of market power) do not directly address the exercise of market power to increase profitability and thereby increase prices, but are focused on lessening competition. As the primary outcome of the exercise of market power in the electricity market is to increase profitability, it would appear that the TPA does not protect consumers against this practice. Nor is there any remedy under common law against what is a modern form of “engrossing” by a dominant supplier.

The assumption behind the approach of the TPA, to address competition aspects, is that it is by competition that consumers will gain the least cost for the provision of a commodity or service. The TPA therefore is predicated on the principle that maximising competition will provide the best outcome for consumers. This is true but competition cannot be easily improved where there is no instant freedom of entry and new generation plant cannot be quickly built and commissioned.

Examining this issue from the viewpoint of a business with market power, suggests it will use its market power to increase its profitability. Yet because it is not using its market power to damage competitors through predatory pricing, the TPA will not apply. The TPA focuses on whether conduct damages competitors, not on the effect of the actual exercise of market power to extract monopoly revenues from consumers and users.

Because of the uniqueness of electricity, (with its low inelasticity of demand, and the need for concurrent supply and usage) attempting to apply general competition laws (such as the TPA) is inadequate.

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[12] For example, Queensland Wire Industries vs BHP

[13] See Rule clause 3.1.4(b). The Energy Reform Implementation Group – ERIG – reiterates this in its report to CoAG and this aspect is more fully developed in section 1.2 and Box 1 below.

[14] The ACCC assessed the acquisition by AGL of part of Loy Yang A under section 50 as they considered there would be a lessening of competition as a result of the acquisition

For example the AER concluded in its report of its rebidding investigation on TIPS[15] that AGL did not transgress the NER. However, this report and in others undertaken by the AER, the AER (a part of the ACCC) did not address whether AGL/TIPS had transgressed the Trade Practices Act. Despite the fact that AGL/TIPS did use its market power to increase its profitability to the detriment of consumers, it was considered that this action did not have an impact on lessening competition, which is the focus of the TPA.

Because the TPA does not prevent the strategic bidding behaviour undertaken by generators in the NEM, and the NER is unable to protect the interests of consumers against the exercise of generator market power, it is clear there is a need to introduce a rule change to constrain the abilities of dominant generators to use their market power to increase the spot price above what would otherwise result if there were adequate competitive pressures.

This case is not unique. Because the TPA does not cover every form of market abuse, the Australian share and futures markets have specific rules against market rigging and price manipulation through abuses of trading orders. These are enforced by the ASX and ASIC and backed by rigorous investigatory powers.

1.2 About generator market power

The exercise of generator market power to manipulate the spot market revolves entirely around the price/volume trade off. If the revenue a generator receives from a higher price achieved for a reduced volume generated exceeds the revenue from a lower price but for a larger volume, then there is a clear commercial incentive for a generator to price its offers strategically when it can do so, or in other words, to use its market power to increase the market price. In the NEM where the market price cap is more than 200 times the long run marginal cost of production, the price/volume trade off favours strategic bidding.

For example, on 13 March 2008, TIPS in the SA region was generating some 696 MW at 1 pm and receiving $100.94/MWh. At 3 pm it was generating 316 MW and receiving $9999.72/MWh. This is shown in the following Figure 1.

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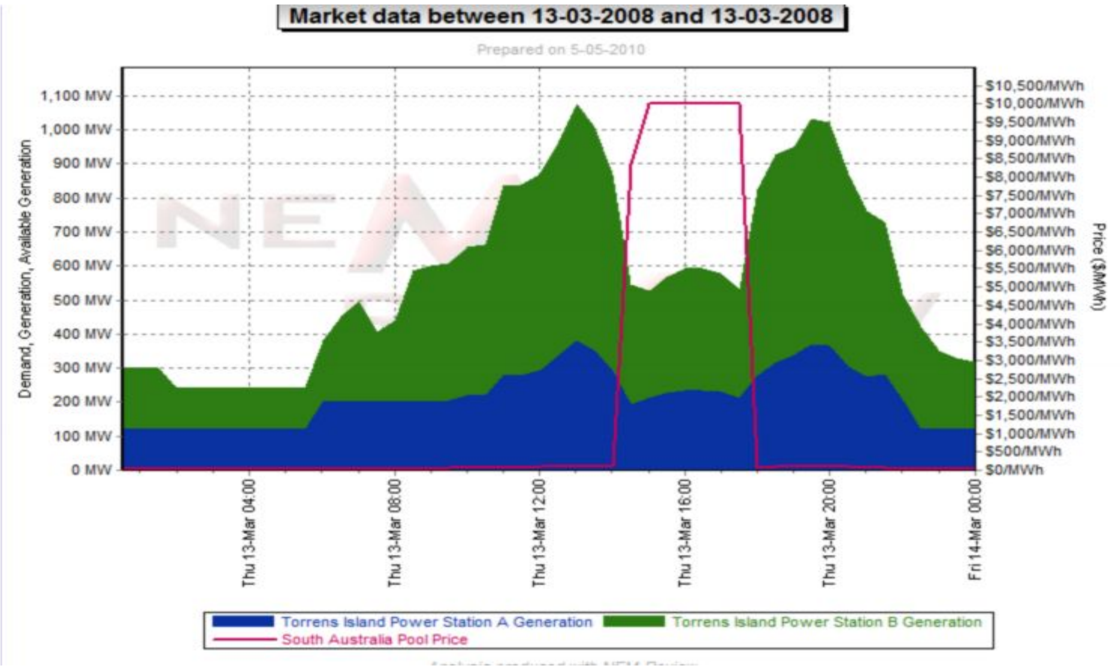
[15] AER Investigation Report AGL's compliance with the good faith rebidding provision of the National Electricity Rules on 19 February 2008 May 2009

Figure 1 – TIPS generation and SA spot price



Thus for an effective reduction of output of 55% its revenue from the spot market increased by 45 times. Over two hours, TIPS was able to increase its 1 pm revenue from $70,254/hr to $3,159,912/hr at 3 pm by using its market power. Clearly exercise of market power is highly profitable. After the high price period (where it had effectively reduced its output) TIPS was later able to sell much more power but at a lower price. This is a clear example of "economic withdrawal" of capacity aimed at increasing revenue.

Even though TIPS was able to maximise its revenue because it had no competition, it was able to use its market power without contravening the TPA.

The California power crisis in 2000 clearly demonstrated the urgency for the need for controls on the exercise of generator market power. As a result of that episode, a staff report concluded[16]"

> "...competitive forces, flawed market rules and, to some extent, market power contributed to the unusually high prices the past summer. These results seem to suggest that some change in market rules is required. Additionally, some further steps during a transition period to 2002, when new capacity will be available, may also be necessary."

There is extensive literature on the exercise of market power in electricity markets and the significant economic harm that results from it. The most

[16] Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities Part I, November 1, 2000

blatant example of exercise of market power is economic withdrawal of supply[17] and this is the approach used by generators in NSW, SA and Tasmania in recent years.

At one end of the scale, exercise of market power increases costs for consumers, and at the other end, it creates an environment where those seeking to invest in new generation are concerned about the quality of their proposed investment. As a result, many regulators (eg FERC in the US and Ofgem in the UK) impose or seek to impose constraints on those generators which have the ability to exercise market power, or apply penalties where generators have done so.

FERC, in particular, decided that there was a need to impose six Market Behaviour Rules to govern sellers' conduct[18] in the wholesale electricity markets in the US. These are included in appendix 3. But most important in relation to this rule change proposal, is behaviour rule 2 which states:

> "**Market Manipulation**: We proposed to prohibit all forms of market manipulation"

In 2000 Ofgem attempted to impose a market abuse licence condition on generators to limit the exercise of their market power. This imposition was subsequently appealed and the Competition Commission rejected Ofgem's proposed licence condition. Ofgem then raised the issue of market power again in 2009[19].This review was effectively superseded by allegations of bidding abuse across the England/Scotland interconnector and in 2010 the UK Parliament has given the Secretary of State the ability to introduce a condition on a generation licence holder, which would constrain the ability of the licence holder to exercise its market power[20].

In 2001, the National Electricity Code Administrator (NECA) proposed to introduce controls aimed at limiting the ability of generators to exercise market power (primarily through rebidding) but these changes were denied by the ACCC in 2002. In its final decision[21] the ACCC observed:

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[17] This is where a generator which must be dispatched to maintain supply, unilaterally prices or reprices its output at the market price cap, causing an unnecessary increase in the spot price.
[18] FERC: Order amending market-based rate tariffs and authorizations (issued November 17, 2003) docket nos. EL01-118-000 and EL01-118-001
[19] Ofgem consultation paper Ref: 30/09 Addressing Market Power Concerns in the Electricity Wholesale Sector - Initial Policy Proposals: 30 March 2009. See http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=42&refer=Markets/WhlMkts/CompandEff
[20] See appendix 4(b)
[21] ACCC, Determination, Applications for Authorisation, Amendments to the National Electricity Code Changes to bidding and rebidding rules, 4 December 2002

> "Significant price spikes have been observed in the spot market between May and July 2002 that appear to have been in part the result of a strategic withdrawal of capacity, increasing year average prices significantly. There is a concern about the ability of generators to affect spot prices and the relative lack of competitive generator response witnessed over this period." (p. ix)

The ACCC determined that there should be introduced a "good faith" provision into the rules to minimise the ability of generators to exercise market power and commented that the Trade Practices Act also assisted in preventing exercise of generator market power.

The Energy Reform Implementation Group (in 2007) discussed the ease with which generators can exercise market power in the NEM (see Box 1), but concluded that, at the time, it was not a significant problem in the NEM, nor was the Trade Practices Act inadequate in protecting consumers. ERIG commented[22]:

> "In assessing market performance overall, ERIG accepts that, in the NEM, there is some evidence of the on-going exercise of market power. This appears to be persistent, but intermittent. The magnitude of non-competitive outcomes appears to be such as to have a material adverse impact on the economic performance of the market. This appears to be most significant in New South Wales.
>
> What should be done about this evidence of transient market power? This is a matter that depends on the nature of the problem. To the extent that the problem appears to be greatest in NSW, in the first instance, structural solutions such as disaggregation and privatisation may be appropriate." (p. 71)

To a degree the ERIG report considers that generator market power was limited to NSW and could be resolved by providing a structural solution. ERIG seems to agree with FERC and international experts who consider electricity markets are easy markets in which to exercise market power, and that the rewards for doing so can be very large[23].

Box 1 – ERIG: On generator market power and SA region experience

"In energy-only markets price spikes are *expected* to occur. The key question is whether the observed volatility is considered efficient (that is, enough to provide the right investment signals), or excessive (that is, too high, and/or lasting too long, suggesting some form of market power or barriers to entry into the market on the supply side).

[22] Energy Reform Implementation Group: Energy Reform The way forward for Australia
A report to the Council of Australian Governments January 2007, page 71
[23] For instance see Frank A. Wolak, An assessment of the performance of the New Zealand wholesale electricity market, 19 May 2009

The benchmark for assessing the efficiency of all markets, including electricity markets, is whether or not observed prices are competitive. Competitive prices occur when the market price, representing the marginal value of an additional unit of consumption, is equated to the cost of producing an additional unit of supply. ... One measure of the efficient performance of the market is the observed closeness of this (price = short run marginal cost) relationship.

Price outcomes in the NEM will deviate from the competitive level whenever a generator has reduced its output from a given level (or conversely raises the minimum price at which it is willing to sell output) and increased its revenues by doing so. In this case, the generator is said to be exercising market power. In an energy only market, only when this behaviour is able to be repeated frequently do concerns arise about market power." (ERIG page 65)

"Market power may be a sustained phenomenon, which points to market structure problems manifested in barriers to market entry. Alternatively, it may be a transient problem, occurring only when demand is at or above certain levels. However, even transient market power can impose significant economic harm even though it occurs for a short period of time (Willet 2005, Wolak 2006).

Both sustained and transient market power can be problems. The former points to removal of entry barriers as the solution. The latter may point to similar solutions, if it results in significant deviations from average efficient prices, even if it lasts for only a short proportion of time. The smaller the economic impact of transient market power, the less it is a problem. Dealing with short-period market power may point more to examining rules governing participant behaviour than to market entry problems." (ERIG page 66)

The clear import of the ERIG observations is that price spikes are a feature of energy-only markets if they result when there is competition between generators, but that if they result from the exercise of market power then steps need to be taken to address this, such as implementing "...rules governing participant behaviour...".

ERIG also comments that there is evidence of market power if "... this behaviour is able to be repeated frequently..." The fact that in the SA region prices have been spiked every summer since 2007 by a base load power station, demonstrates the presence of market power.

ERIG observes that the market will be efficient if the prices are competitive, and the closer prices get to short run marginal cost, the more competitive the market is. In the SA region, spot prices have increased by more than 50% since the acquisition of TIPS by AGL in 2007 even though no other region has exhibited such large increases.

Since the summer of 2007/08, contract prices have also increased by up to 50% as well. In early 2008, the MEU provided the AER with confidential survey results from the SA members of MEU who were negotiating or had just completed negotiating for retail contracts. The members generally had experienced a reduction in the number of retailers prepared to make offers and seen retail price offerings increase by up to 50% from the previous prices they had contracted for, reflecting the spot price movements. This observation is replicated by price movements indentified in the futures market– see appendix 7.

Following this, in another confidential submission to the AER, the MEU provided case studies of members who were exposed to the spot market during the price events. Despite significant demand reductions at the times of high prices, the members incurred substantial increased costs as a result of the persistent price spikes.

The SA region has seen persistent exercise of generator market power which has caused a considerable transfer of wealth from consumers to generators through both the contract market and the spot market. Further the prices for power are considerably more than the short run marginal cost, indicating that competition in the SA region is very low.

What is apparent is that there is general agreement that electricity markets are susceptible to the exercise of generator market power and that action is needed to ensure that the outcomes of this exercise need to be limited – by structural means (as ERIG in the case of NSW generators suggests and was carried out in Britain over the period 1995-2000 by forced divestments) or by rule changes (as FERC has implemented).

Despite this consensus of view, the NEM Rules consider that the TPA is adequate to protect the interests of consumers against market manipulation. Rule clause 3.1.4(b) states

> "This Chapter [3 Market Rules] is not intended to regulate anti-competitive behaviour by *Market Participants* which, as in all other markets, is subject to the relevant provisions of the Trade Practices Act, 1974 and the Competition Codes of *participating jurisdictions*."

This is in stark contrast to the views of ERIG which states (page 141)

> "ERIG has found some evidence that is suggestive of non-competitive market outcomes having an adverse impact on the economic performance of the NEM ... Individual behaviour of generators within the NEM, in compliance with the NEL rules, is not illegal under the TPA ... **ERIG does not believe that changes to the TPA are an appropriate response ... [and] notes that, overseas, competition issues (eg, market power mitigation) are explicitly covered**

> **within market design and operating rules, rather than through adjustments to competition policy instruments such as the TPA.**
>
> With the exception of the requirement that generators bid 'in good faith', the NEL currently does not address market power specifically, or even the conditions under which it would be appropriate to do so. This appears to be in contrast with 'best practice' considerations for managing unilateral market power in electricity markets (see, for example, Wolak 2006)." (Emphasis added)

Notwithstanding this considerable support for ensuring electricity market rules limit the exercise of generator market power, before such a change should be implemented it is necessary to identify if there is a net benefit from making such a change, such as the ACCC did in its recent decision preventing the NSW government from implementing its proposed co-insurance scheme in the sale of gentraders. The benefits and detriments of the proposed rule change are discussed in more detail in sections 7 and 8 of this proposal.

Overall, the MEU considers that the weight of specific international and domestic evidence supports an approach being made to constrain the exercise of generator market power, especially by the dominant generators in each NEM region.

1.3 Overseas experience

Attached to this rule change proposal (as appendices 4(a) and 4(b)) is a report commissioned by MEU, and carried out by EEE Ltd[24]. EEE has advised the AER and other regulatory bodies in Australia on a number of energy issues. The EEE report provides an insight into the concerns regulatory bodies in overseas jurisdictions have regarding generator market power, and the approaches used to limit the exercise of this power.

Section 3 of the EEE report describes, in general terms, the concept of market power and anti-trust. It makes reference to a 2005 European Commission discussion paper[25] on the issue. This discussion paper posits the concept that:

> "An undertaking that is capable of substantially increasing prices above the competitive level for a significant period of time holds substantial market power and possesses the requisite ability to act to an appreciable extent independently of competitors, customers and consumers. Unlike undertakings in a market characterised by effective competition, a dominant undertaking

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[24] Generator Market Power in the Electricity Supply Industry, A review of the mitigation of generator market power in the British, Albertan, US North Eastern, and Texan electricity markets, by Alex Henney EEE Ltd, October 2008

[25] EUROPEAN COMMISSION, DG Competition, Brussels, December 2005. DG Competition discussion paper on the application of Article 82 of the Treaty to exclusionary abuses

> not subject to effective competitive constraints is able to price above the competitive level. It can do so by reducing its own output or by causing rivals to reduce their output."

This description provides this rule change proposal with a clear but basic concept of what market power and dominance are in relation to the NEM, and what should be expected if there were strong competition. These basic concepts are used throughout this rule change proposal.

What is most notable about the EEE report is:

1. Exercise of market power in electricity markets is relatively easy and can cause significant commercial harm to consumers
2. Approaches to address the exercise of generator market power have been widely used and cover three different forms – structural, ex ante and ex post (see section 4 below for a more detailed assessment of each of these approaches and how each might apply in the NEM).
3. Although the rule makers for each electricity market have identified there are difficulties and negative impacts of introducing constraints on the exercise of generator market power, this has not deterred them from proceeding to do so.

In contrast, the NEM only requires that generators bid "in good faith", and it is obvious that bidding to seek an improved commercial outcome (ie higher profits) is (and should be) recognised as bidding "in good faith".

1.4 At what point does generator market power become a problem?

The fact that a generator may have market power is not the main issue. For much of the time a generator with market power is not able to exercise it. The problem arises when a generator which does have market power elects to exercise it because the conditions are favourable and profitable.

The demand levels at which dominant generators in each region of the NEM can profitably exercise market power and spike prices[26] (and thereby engineer large wealth transfers from consumers to generators) are considerably below recorded peak demand levels in most NEM regions.

For example, the AER has identified that the dominant generator in SA (Torrens Island Power Station – TIPS) is able to set prices when demand reaches ~2500 MW[27], which is about 25% below the regional peak demand of 3331 MW. TIPS has been able to regularly spike spot prices, as seen in the

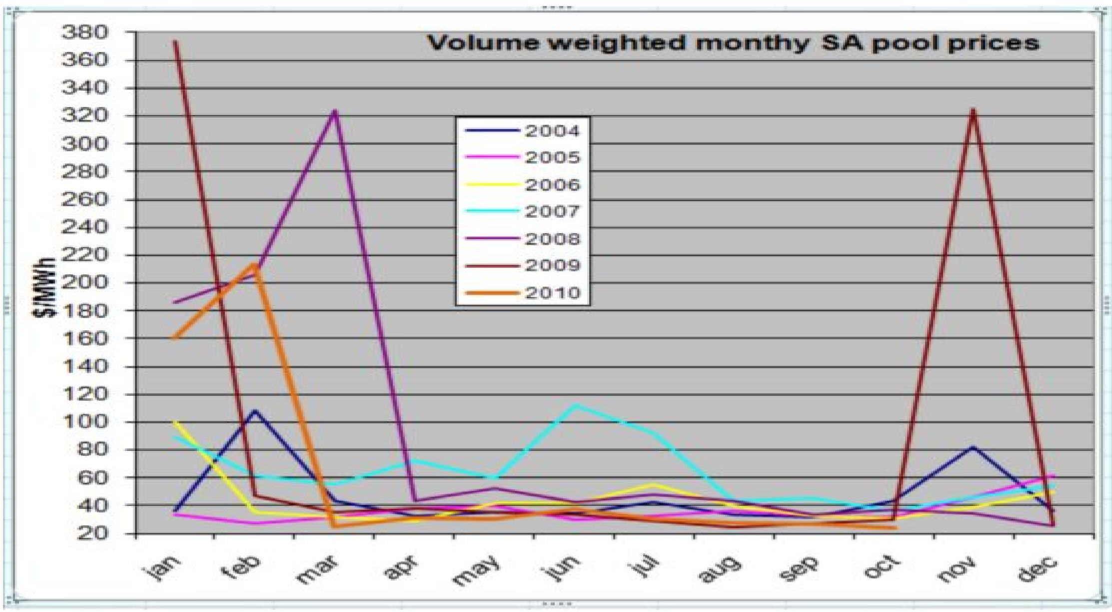
[26] See appendix 2 showing the impact of price spikes in the NEM, and the influence of the relatively few price spikes that do occur
[27] See Ed Willett (ACCC commissioner and AER member) presentation State of the Energy Market to energy 21C in Melbourne, 8 September 2009

summer months of 2008, 2009 and 2010. In NSW and Tasmania, the dominant generators can also exercise market power at regional demands well below the peak demands in those regions.[28]

The NEM has become increasingly concentrated, especially with the structural aggregation of generators with retailers, to form a new business structure by the creation of "gentailers". For example, in South Australia, the bulk of retailing and generation is controlled by "gentailers" AGL Energy and Origin Energy. The output of the independent generators (Pelican Point power station owned by International Power and Northern and Playford power stations owned by Alinta Energy – both base load generators) is heavily contracted to the two largest retailers AGL (60% market share) and Origin (15%). A description of the impact of this integration of generation and retail is more fully explained in appendix 6.

With the ease at which market power can so readily be exercised, consumers are now heavily exposed to aggressive profit maximization generator bidding strategies. In SA region the dominant generator has frequently exercised market power in warmer months, and driven the monthly average prices up to six times the annual average prices. As a result, annual average spot prices (and consequently the contract prices) in SA region are the highest in the NEM by a significant margin, which is not caused by generation mix and fuels used. Figure 2 graphs the SA monthly average volume weighted spot prices for the years 2004 to 2010. It clearly shows how AGL has used its ownership of TIPS since it acquired TIPS in 2007, to increase spot prices.

Figure 2 – Monthly volume weighted spot prices in SA



Source: AEMO Data

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[28] See section 5 for the definitions used by the proposal for dominance and market power

Whilst the market as currently designed was developed to send price signals for new generation investment (and for consumers to modify their electricity usage), it is now apparent that, at the current market settings, new generation investment is not driven by the spot market price signals to the extent envisaged. For example, in SA the market signals since 2007 (driven by the exercise of market power by TIPS) would indicate there is a major need for new generation investment yet the market itself has decided that these signals are basically spurious, as the only recent significant investment in new dispatchable generation in SA has been the augmentation of Origin Energy's Quarantine peaking power station[29].

Observations made by those investing in generation now, are that investment is driven by those willing to contract for the new capacity, allowing the investment to be effectively underwritten[30].

It is clear that, in the absence of market power or manipulation mitigating measures, the NEM institutions and the NEM Rules are increasingly less effective in ensuring that the NEM is operating in "…the long term interests of consumers".

[29] There has been of course significant investment in wind farms in SA but this has been driven by the renewable energy target scheme.
[30] Origin Energy, Dennis Barnes' Presentation at Public Forum, 12 February 2010 "Response to Review on Reliability Standard and Settings Draft Report

2. A summary view of the current status of the NEM

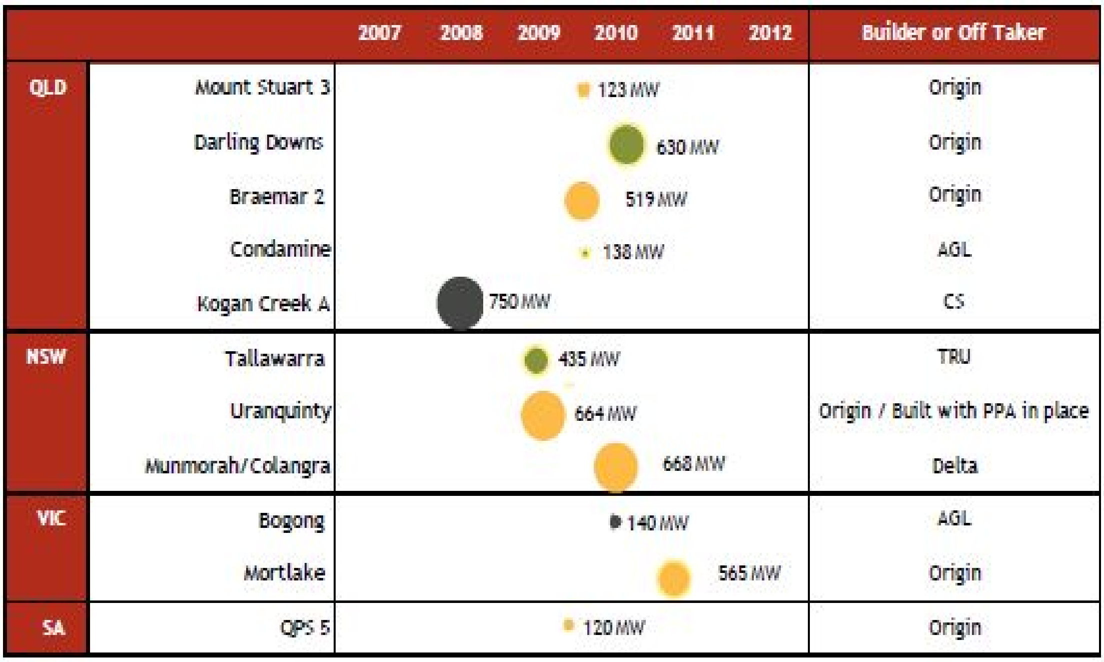
The NEM is seen as increasingly becoming more concentrated, with a small number of large companies engaged in providing multi-fuels (of electricity and gas), and a number of second tier retailers have either exited the market or becoming less active.

Vertical re-integration of the electricity market has been permitted by the ACCC (eg AGL acquisition of part of Loy Yang A and AGL acquisition of TIPS), thereby allowing greater market influence. In South Australia, this re-integration has permitted the combining of the dominant regional generator with a dominant regional retailer.

The NEM is even more highly volatile with an increasing prevalence of price spikes increasing market risks and hence costs, and the decision to increase the Market Price Cap by 25% to $12,500/MWh from July 2010 is likely to exacerbate this volatility.

A consequence of this increased volatility Is that barriers to new entry (generation and retail) are higher due to increased market risks and prudency requirements, as a result of the above noted features. One major outcome of this has been that large electricity retailers are becoming the main investors in new generation assets as shown in the following figure 3 provided by Origin Energy in its recent submission to the Reliability Panel in February 2010.

Figure 3- Recent generator investment decisions and announced projects



Source: Origin Energy submission to Reliability Panel 24 February 2010

In addition to these features, consumers have seen:

- The limited capacity on inter-regional interconnections being often quickly constrained by congestion during hot weather periods. The increasing development of intermittent wind generation has increased inter- and intra-regional congestion.

- The recent changes to the NER for network pricing has seen the cost of electricity transport rise significantly with the long term expectation this trend will continue[31].

- There is inadequate liquidity of hedging products used in the NEM, especially in the futures market, needed to help consumers and retailers cover their risks. Often the prices for these products are significantly high, reflecting supply scarcity.

- The NEM is driven by the premise that the market price cap (MPC) for an energy-only market needs to be high to ensure there are adequate market signals to encourage investment in new generation. However, there is an increasingly stated and widely held view of market participants that there is also an upper limit for the MPC, because if it is too high risk and prudential requirements for participants increase, resulting in additional costs to participants.

As a result of these factors, prices for electricity have trended well beyond the cost of production. A feature of the energy only market with a very high market price cap, and some very large generators, has been an increasing frequency in base and mid merit generators manipulating the spot markets. This trend has been especially noticeable in the SA region.

The high pricing and lack of competition in the electricity markets has caused large consumers to look to alternative means to keep their costs within reasonable bounds, such as taking spot price risk combined with demand modification and/or looking at self generation. Additionally, there have been some views expressed that large consumers in a region could combine their electricity demands and sponsor their own generation facility to obviate the market risks. But while these actions might be considered to be supportive of the current electricity market approach such options are not the most economically beneficial for consumers, as an efficient electricity market benefitting from economies of scale, should provide a better outcome for all consumers.

[31] In NSW, MEU members saw network charges undergo a step increase of between 30% and 50% in 2010.

Our rule change proposal is a result of observed manipulation of the spot market by generators and is designed to limit the ability of generators who have market power to exercise it (thereby benefiting consumers), but at the same time, to ensure there is still adequate incentive to invest in new generation.

3. General commentary on generator dispatch to achieve the most efficient outcome

In a vertically integrated electricity system the system operator would dispatch those generators needed to provide base load power firstly to an output level that permits stable operation. Then, further output would be provided from the lowest cost generator first, followed by higher cost generation.

Base and mid merit generators commonly have physical constraints (eg ramp rates, minimum output levels) which impose operational limitations for provision of power and therefore impact their pricing approaches. Peaking generators are included in the generation mix to provide fast start and short periods of operation.

The NEM is premised on providing a framework which effectively replicates the dispatch process that the operator of a vertically integrated system would achieve by dispatching the most economically efficient output from the mix of generators under its control, to match the system demand. The expectation of the NEM framework is that dispatch of generators in each region will result in the most efficient and lowest cost outcome, reflecting the costs of generation and the duration of dispatch.

It is a recognition of the different operational approaches provided by the different types of generators that is used to set the market price cap. The market price cap of $12,500/MWh was developed on the basis that it was the price of power needed to be paid to recover the long run marginal cost (LRMC) of a peaking generator which operates for only a few (between 8-12) hours each year. Such high prices are not required to recompense base and mid merit generation which operate frequently and for long periods of time.

A feature of the NEM is that it is designed to send signals to indicate scarcity of generation supply. Essentially there are two price signals that are required to signal scarcity of supply – prices spikes indicate a short term scarcity, and a high long term median price indicates long term scarcity.

Market supporters point to the fact that the price spikes observed in the market are a necessary feature of this signalling. As the observed price spikes tend to occur at periods of high regional demand which typically occur for relative short periods of time, the market signals only indicate that there is a shortage of generation to serve relative short periods of very high demand. To address short term scarcity, generation which is readily able to operate infrequently but very quickly is needed. Traditionally this is called “peaking generation.

In contrast a **high median** spot price (exceeding the long run marginal cost) tends to indicate a scarcity of base and mid merit generation.

Frequent prices spikes also result in a long term **high average** spot price and a high average spot price will “cloud out” the price signal of a high median spot price which is the signal for base and mid merit generation.

It is therefore not expected that base and mid merit generation need price signals caused by frequent price spikes. Base and mid merit generators are perforce large in capacity and this means that they are more likely to be dominant generators in the market. Despite this, it has been the base and mid merit generation that has used its market power to set the spot price at such high levels. For instance, in SA, TIPS (the largest in the region and used as a base generator for decades), along with Macquarie Generation in NSW (a large base load generator) have been cited by the AER as using their market power to set the regional price.

If the price spike market signals are targeted to supply signals to peaking generators, it is not intended that base load and mid merit generation should be using their market power manipulate supply and to sell their output at prices intended to recompense generation which is expected to operate infrequently.

Our proposed rule change is targeted entirely to preclude base load and mid merit generation from setting the regional price at excessively high levels which are not appropriate for the generation type. Equally the rule change proposal is structured so that it will not reduce the incentives for investment in peaking generation which needs high prices for the relative short times they are required to operate, nor to reduce the long term median price which provides a signal for new base and mid merit generation.

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4. Approaches available to limit market power

Essentially there are three approaches used in electricity markets to limit the exercise of market power, viz:

- Structural, where no generator is permitted to be large enough to control the price at any level of demand (ie that there is strong competition at all levels of demand)
- Ex ante, where the regulator imposes rules preventing a dominant generator from offering prices for its power outside its normal operating envelop for output and price
- Ex post, where the regulator imposes recoveries of costs and/or penalties on a generator after it has exercised its market power

In the NEM, the **structural** approach is not viable as the NEM was derived from a series of regional structures developed as vertically integrated systems, where a few large generators were built as the most economical solution for each region. To eliminate the potential for market power would require the government owners of the generation to have reduced all generation corporations to single generation sites as was carried out in Victoria, and even in Victoria where this was done, the largest generator there (Loy Yang A) has the potential to exercise its market power. In other regions, TIPS in SA, CS Energy in Queensland, Macquarie and Delta in NSW and Tas Hydro in Tasmania all have market power because the government owners did not corporatize into single power station units.

An **ex ante** approach is designed to limit the ability of a dominant generator from offering prices outside a competitively based operating envelop. This is best suited where there is a transparent spot market based on generator offers that can be related to their costs. The ex ante approach would only need to apply at times where the dominant generator has the ability to exercise market power. Because for the most part, all generators are constrained by competition, it is relatively straight forward to develop a normal operating envelop for price and output for a dominant generator[32].

An **ex post** approach is better suited to a market where there is limited competition, and a regulator is readily able to identify the costs (and who incurred them) of the application of market power. As the NEM is designed to deliver high levels of competition (at least for most of the time) and therefore provides competitively priced power for those periods, the ex post approach is less likely to be more effective than an ex ante approach in limiting price manipulation.

[32] In the US, generators supply to the regulator their heat rate and the spot price for coal or gas is used to calculate the generation costs.

A more detailed analysis of the ex ante and ex post options is provided in appendix 1

On balance, the MEU considers that an ex ante approach is better suited to the NEM.

Our proposed market power mitigation approach has many features similar to that used by the New York ISO and which has been approved for use by FERC. NYISO features the following key elements[33]:

- There is analysis as to which generators have market power and where.
- Those generators with market power are advised as to their status as such, and are expected to comply with the requirements of not using their market power to increase the spot price excessively.
- The conduct of generators which have market power is assessed.
- The dispatch program checks if offers from a generator with market power will significantly impact the spot price.
- If the dispatch program assesses that the offer will affect the market price, the program automatically implements a default price for the generator.

Although it is observed the NYISO operates a "capacity" market, the revenue from selling energy is such a large element of the total revenue needed by a generator, the MEU considers the approach can be used as a guide to mitigating market manipulation.

[33] See section 7.3.1 of the report in appendix 4 which provides more detail on how NYISO limits the exercise of market power

5. The MEU proposed rule change concept

For the purposes of this proposed rule change, the terms,

- "Dominant generator" denotes a generator (or generators) which has (or have) the ability to profitably manipulate prices in the spot market for electricity at regional demand levels below the peak demand observed in that region. The process by which a dominant generator would be identified is that if it can be demonstrated that the maximum regional demand at any time cannot be met without dispatch of that generator, then that generator is a "dominant generator" [34].

- "Generator market power" means an ability of a generator to manipulate the spot price at a regional demand less than the maximum regional demand, by either physical or economic withholding of its capacity[35].

This proposed rule change has the following structure:

- The dominant generator(s) in each region are to be declared under the Rules as a "dominant generator(s)". The declaration process will be conducted by the AER and the criteria for assessing the conditions under which a generator(s) is classified as a dominant generator would be based on a regulatory assessment of regional demand and other conditions under which the dominant generator(s) is able, at particular demand levels in a region, to set prices without any effective competition from other generators or has the ability to manipulate prices and supply in a regional market, to the extent that the actions of other competitors will have no effect in influencing or establishing the regional spot price[36].

  This declaration process would also identify other generators which have market dominance at higher regional demand levels than that of the largest generator, and the regional demand levels at which these

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[34] In electricity markets, market manipulation by base load and mid merit generation has been observed to drive up spot prices many times beyond Long Run Marginal Cost of such generation and this has resulted in a pricing outcome that does not reflect competition. Such actions have been observed to be sustained, for example in the summer months of 2008, 2009 and 2010 in South Australia.

[35] This MEU concept of market power used in this rule change proposal has a high degree of consistency with the AER description used in the AER's Proposed Regulatory Test Application Guidelines July 2007 page 9, which states "A *Market Participant* has a degree of market power in a given *dispatch interval* if it can, by varying its bid or offer, alter the pricing, *dispatch* and flow outcomes in the *market* (including possibly inducing 'clamping') in that *dispatch interval* in a manner that is profitable for that firm.

[36] As noted earlier, the AER has advised it considers that in SA region, TIPS has market power when the SA regional demand exceeds 2500 MW.

smaller generators could exercise market power[37] (see examples in section 6). As peaking generation power stations are commonly smaller than base and mid merit generation power stations, it is not expected that peaking generation will be captured by this declaration process.

- Once the regional demand where the AER has determined the dominant generator(s) have market power is reached, the dominant generator(s) in each region will be prohibited from exercising economic or physical withdrawal of capacity, and will be required to dispatch all of its available capacity at less than a predetermined price.

- The dominant generator(s) in each region can submit bids at any price until the predetermined regional demand is reached.

    - This predetermined regional demand level would be the same as that used in determining whether there is a “dominant generator(s)” in the region and the level at which the generator(s) is considered to be dominant.
    - Above that predetermined regional demand level, the “dominant generator(s)” is constrained to offer its output at no more than a predetermined price. This proposal suggests that this maximum price should be no more that the Administered Price Cap (APC)[38]. This predetermined price cap applying to the dominant generator(s) will be called the “dominant generator price cap”.

- All generators not classified as being “dominant” will not be restrained from bidding at any price level up to the Market Price Cap.

- When the regional demand reaches or exceeds the value set by the AER in determining a dominant generator(s), AEMO shall “call” on the dominant generator to dispatch, or offer for dispatch, all of its available capacity at the dominant generator price cap.

- The “dominant generator(s)” will receive the regional reference price for its output set by it and competing generators.

- As all other generators would be dispatched in accordance with their offers, market integrity is maintained except for constraining the pricing of only the dominant generator(s).

- When the regional demand exceeds the value assessed by the AER for identifying a dominant generator(s), and if higher priced generators must

[37] Section 7.2 provides the concepts under which the AER would identify the regional demand levels at which the dominant generator is able to exercise its market power.
[38] See section 8.2.1.2 as to why the MEU considers the APC is an appropriate level for the “dominant generator price cap”.

be dispatched after all the capacity of the dominant generator(s) has been dispatched and the regional the spot price exceeds the dominant generator price cap, then all generators (including the dominant generator) will receive the regional reference price, effectively retaining the integrity of the market structure.

- The dominant generator(s) will be required to offer all of its (their) capacity to the market. If the AER considers that this has not occurred, then the AER will recover the windfall profit from the dominant generator which will also be fined as well.

This proposal is unlikely to negatively impact on investment for new generation and possibly will enhance it because, with the current high level of the market price cap, the variability and extreme volatility of spot prices in an energy-only market means that investment in new generation is driven by the contract market rather than the spot market[39]. As contract prices under the current electricity market settings, rather than the spot price, are seen to drive generation investment, the MEU proposal is not expected to deter new investments in generation capacity.

These aspects are discussed in more detail in sections 7 and 8 of this proposal.

[39] Origin Energy, Submission to Review of the Reliability Standard and Settings – Draft Report. 24 February 2010. In this submission, Origin Energy states: "The inherent volatility of energy-only spot markets is also why the contract market tends to bring forward investment in new generation ahead of any tightening of the underlying supply and demand balance: retailers do not wish to be exposed to extended periods of extreme prices that could arise as a consequence of investment arriving too late. Before this point is reached, retailers will increase their demand in the contract market, establish a longer term Purchase Power Agreement (PPA), or invest in physical generation options, in order to ensure sufficient generation capacity is forthcoming to meet their load requirements at a reasonable cost. This natural incentive supports sustained reliability of supply for consumers".

6. Examples on how the proposal would work.

Example 1 – one dominant generator

The AER currently considers that in SA, TIPS has the ability to have market power and set prices when regional demand exceeds 2500 MW.

- When the regional demand is below the 2500 MW the market would operate normally without constraint on pricing by generators.
- When regional demand reaches 2500 MW, AEMO would call on TIPS (as the dominant generator) to increase its output to match demand.
- Once demand exceeds 2500 MW, TIPS would be constrained to offer all of its capacity at a price not exceeding the administered price cap (APC). This should hold the market price at no more than the APC until TIPS has provided all of its available capacity to the market.

Once the TIPS offers for all of its generation have been included in the bid stack at a price not exceeding the APC, then AEMO would then dispatch generators whose offers exceed the APC. The regional reference price would reflect the bid last dispatched.

All generators dispatched (including the dominant generator) would receive the regional reference price for their output.

Example 2 – two dominant generators[40]

In NSW, Macquarie Generation has market power when regional demand exceeds ~12000 MW. In addition Delta Electricity has market power when regional demand exceeds ~12,500 MW.

Thus when regional demand exceeds ~12000 MW Macquarie Generation would be the dominant generator and would therefore be constrained to offer its output at APC and to offer all of its available capacity to the market at this price.

If demand increased above 12,500 MW, Delta would become a dominant generator as well. At 12,500 MW regional demand, Delta would be declared a dominant generator (along with Macquarie) and have its price offers limited to APC, and to provide all of its available capacity to the market at this price.

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[40] The concept of having more than one dominant generator in a region is not unusual. For example New England ISO recognises there might be more than one (see Appendix 4 section 7.3.2) and PJM ISO assumes there might be as many as three (see Appendix 4 section 7.3.3) that need to be assessed.

If there are other generators (eg Eraring Energy) which have the ability to set the regional price before the regional demand reached its maximum, then they too would be declared a dominant generator and be constrained in a similar manner.

Once the Macquarie and Delta (and other dominant generators) offers for all of their available capacity have been included in the bid stack at APC, then AEMO would include these with bids from other generators whose prices exceed the APC.

All generators dispatched (including the dominant generator) would receive the regional reference price for their output.

7. Assessment of the proposed approach

There are at least three considerations with the proposed approach which need to be addressed in more detail – withholding physical capacity to achieve the same outcome as economic withholding, identifying the precondition for the exercise of market power, and the impact of tacit collusion.

7.1 Withholding physical capacity

Currently the dominant generator in a region manipulates the market by “economic” withholding of capacity[41]. This is achieved by the dominant generator, knowing that once the regional demand reaches a certain point, it has to be dispatched regardless of the price it offers. Thus it can price the bulk of its capacity at the market price cap (MPC) because above this level, there is no competition. In other jurisdictions these generators are referred to as pivotal generators.

Under this proposed rule change, the maximum price the dominant generator will be paid will be the administered price cap (APC) for its output.

The dominant generator could achieve the same outcome as it does by economic withdrawal of capacity by reducing the physical capacity it offers to the market when its price is constrained to the APC.

The risks of doing this are greater for the market than economic withholding because if the amount physically withheld is too great, there is a risk that there will be insufficient generation offered to the market and involuntary load shedding will have to occur.

Conversely, the risk to the dominant generator is high if the physical amount withheld is too small, as the dominant generator will not achieve the goal of getting the price raised to the MPC, and therefore it will not get any “super benefit".

From a generation investment incentive viewpoint, the second concern is not a significant issue, and the dominant generator is not severely impacted as it still receives an enhanced benefit (compared to full competition) of being paid the APC which is still much greater than its LRMC of generation.

The first concern is significant as involuntary load shedding causes major loss to consumers, possibly in excess of the cost of allowing unfettered exercise of market power. To overcome this problem, it will be necessary for the regulator (AER) to have powers to assess whether the dominant generator has offered

[41] Economic withholding is where the generator prices its capacity near the market price cap, and so is less likely to be dispatched as other generators will be dispatched ahead of it.

all of its available capacity to the market. Such an investigation will be intrusive and challenging, but it is possible to undertake. For example, in a capacity market, generators only receive their capacity payments if they have offered their full available capacity to the market. When there is a view that they have failed to do this, the onus is on the generator to prove that it has done so, and if it is found it did not offer its full available capacity then its capacity payments are reduced.

A fundamental feature of the NEM is that no generator can be forced to supply into the market, but at the same time there are elements of the rules and the operation of the NEM that over-ride this precept.

1. If there is intra-regional congestion that prevents power flow from a lower priced generator into a part of the region, AEMO has the power to dispatch a generator out of merit order to ensure that there is adequate supply across the region. In such an instance, the generator dispatched out of merit order receives compensation from AEMO to address its higher costs of generation, as the regional price is unaffected and so the generator dispatched out of merit order would not receive any commercial benefit for being dispatched.

2. Under the rules at present AEMO has the power to “call” a generator to supply (even if the generator has not offered itself for dispatch) if there is a risk of insufficient supply in a part of the NEM; this power is, again, usually triggered by congestion preventing free flow of electricity to a part of the NEM. If such a generator is called, it receives compensation for being required to be dispatched.

3. AEMO has the ability (and needs this ability) to remotely adjust the output of every generator on a continuous basis. This is because demand varies continuously but generator bids are made on a five minute basis. Variations of demand occur more frequently than each five minute period, requiring AEMO to be able to make fine adjustments to a generator’s output on a continuous basis to match supply with demand.

Implicitly and explicitly, the rules already permit AEMO to require generators to be dispatched, although such powers are limited to specific technical aspects such as maintaining security of the system, safety and reliability of supply. The rules also require AEMO to provide financial compensation to those generators which are required to be “constrained on” for such reasons.

It is recognised that the powers to require dispatch do not currently apply to overcome commercial issues in the NEM. This rule change extends the powers in the rules already granted AEMO to “constrain on” a generator but retains much the same principles as already exist within the rules. The generator "constrained on" under this rule change would also receive compensation in that it would receive payment at the same level as the APC.

To ensure that the dominant generator provides all of its available capacity, this proposal therefore requires, if the regulator so determines, a dominant generator has to demonstrate to the AER in an ex post review, that at times when it could exercise market power, it did offer all of its available capacity to the market.

In a capacity market, a generator is paid to provide a certain amount of generation capacity available when called. If the generator fails to provide this capacity it must provide evidence why it was not able to do so, and that this failure was beyond its control. Otherwise it loses the payments associated with capacity offer[42]. As this process has already been used in other markets, it is anticipated that the AER should be able to readily carry out such an analysis.

There is one specific feature of the dispatch of base and mid merit generation plants that the AER would have to consider as part of its analysis as to whether all available capacity had been dispatched by the dominant generator – whether the ramp rates of the physical plant (ie the ability to respond to changed demands) precluded the expectation of some capacity being brought into the market. In this regard, it is expected (as occurs in capacity markets) that in the assessment of whether all available capacity had been offered to the market, the AER would have to have regard to a number of factors such as:

- The amount of capacity already in use before the introduction of the price control,
- The amount of capacity offered subsequent to the removal of the price control
- Amounts of capacity offered at other times (particularly in the days before and after the times under investigation) when the price control did not apply
- The previous demonstrated ability of the generation plant to ramp up and down as demand requirements change,
- Whether the decision to remove some plant elements from service when there was an expectation of a high demand, was warranted or appropriate
- Whether any capacity limits imposed during the time of the price control were necessary or typical of limits applied at other times.

To a degree, the decision to use the APC as the price the dominant generator will be paid when it has market power provides some incentive to the dominant generator to offer all of its available capacity as the price it receives is well

[42] In the New England Forward Capacity Market it would have to pay for lost generation up to the level of the strike price.

above the short run marginal cost that it would otherwise receive if there was strong competition.

In the event that the regulator does not consider that the dominant generator has offered all its available rated capacity, the onus will be on the dominant generator to prove that it did. If the regulator concludes that it did physically withhold capacity, then there must be a penalty applied for this misconduct.

The current maximum fine permitted under the NEL is currently $1m, yet the rewards for withholding physical capacity can easily be more than this fine[43]. Thus the estimated benefit the dominant generator received by its misconduct should be forfeited as well as the fine being imposed[44].

This proposal considers that the threat of potential penalties and an intrusive review balanced by receiving the APC for electricity dispatched that provides the incentives for offering all available capacity by the dominant generator when the conditions would otherwise allow it to exercise of market power.

It is accepted that as a result of this rule change the AER will need to have the necessary access to resources and funds to carry out such a detailed review to assess whether a generator has provided all of its available capacity to the market and not deliberately withheld physical capacity. Because of this there is likely to be a significant cost to the regulator to carry out such a review. The MEU considers that such a review might cost between $100,000-200,000. This amount is small compared to the rewards a generator may achieve by exercising market power where it might receive many millions of dollars per hour.

As the likely cost the AER will incur is significantly less than the likely transfer of wealth from consumers to generators, the cost to benefit analysis shows that the rule change overall provides a net benefit.

There is one aspect that deserves further consideration. Under the TPA section 155(1)(a)(b)(c) the ACCC has various powers to investigate and collect information (e.g. conducting interviews under oath) which, if the AER had similar powers, would give the AER a greater ability to determine whether generators had legitimately not presented all available capacity to the market.

The MEU considers that having such powers would greatly assist the AER in developing an accurate view of the circumstances surrounding establishing whether the dominant generator had in fact provided all of its available capacity to the market as required by this rule change.

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[43] For example see appendix A5.3 where on 18 February 2008 TIPS was earning revenue at the rate of $5.2m per hour while supplying half the output it did earlier in the day when its revenue was $67,000 per hour.,

[44] For example, in the UK, if a market participant breaches a licence condition it can be fined up to 10% of its turnover, but the fine has to be proportionate.

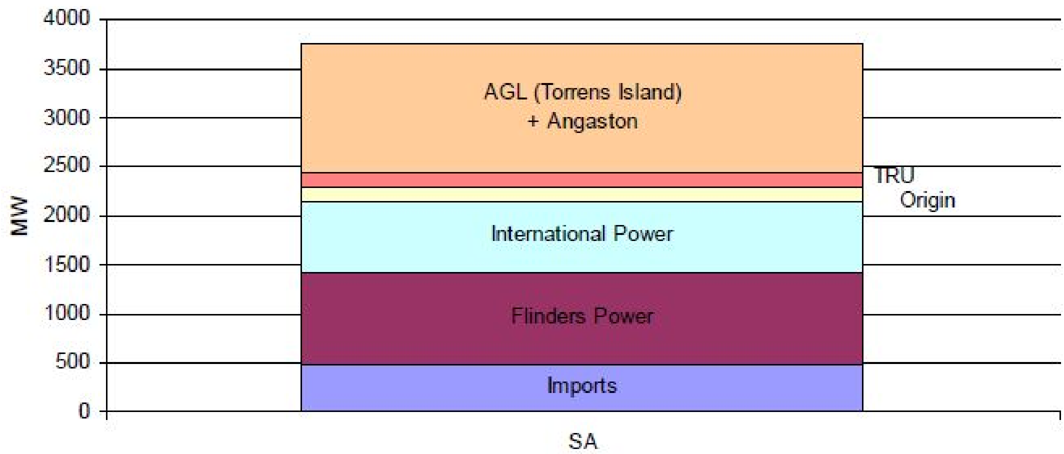
To overcome the limitations in AER powers, the MEU considers either the NEL should be modified to provide the AER with the necessary investigative powers, or the rules could allow the ACCC to carry out these investigations using its powers under the TPA. In this regard we note that the ASX and ASIC have (or have had) similar powers in relation to investigations of stock market rigging practices, so such a solution as proposed by the MEU has a clear precedent.

7.2 Identifying the precondition for exercise of market power

The first step of identifying the preconditions for exercising market power, is to identify if there is a concern. For example, already the AER has identified that TIPS has market power in the SA region when regional demand exceeds 2500 MW[45]. The AER comments

> "...when demand exceeds 2500 MW, Torrens Island power station must be dispatched. That is, when demand exceeds 2500 MW Torrens Island power station becomes the marginal generator.

Figure 4 – Supply options in South Australia



Source: AER report on Spot prices greater than $5000/MWh South Australia: 5 - 17 March 2008, page 5

The second part of the assessment requires the AER to identify if the point at which the dominant generator has market power, is higher or lower than the highest expected demand in a region.

For example, in Queensland, the dominant generator (CS Energy) would have market power when demand approaches 10,000 MW. The highest peak demand recorded in Queensland so far is less than 9000 MW so CS Energy has not had the ability to use its market power to date. However, the 2009

[45] AER report on Spot prices greater than $5000/MWh South Australia: 5 - 17 March 2008, page 5

Electricity Statement of Opportunities (ESoO) forecasts on a 10% Probability of Exceedence (PoE) that demand in Queensland is likely to exceed 10,000 MW in 2009/10 indicating that CS Energy might soon have this ability.

This rule change proposal recommends that the AER should develop guidelines so that its assessment of which generators are dominant would use the trigger of 10%PoE as the basis, rather than using the highest recorded demands.

If this assessment indicates that in a region no generator is likely to have market power for the next summer (when highest peaks occur in the NEM) then there will be no need to declare a dominant generator in that region.

In a similar manner the AER can determine those generators in other regions that have market power once the regional demand reaches a certain level. It is expected that the AER would be required to develop guidelines under which it would assess the pre-determined regional demand for the exercise of market power. These guidelines would have to address the issues that if the per-determined level is set too high, then the bidding restriction would never need to be enforced, but if set too low, it would have the potential to constrain the market unnecessarily and perhaps even reduce the incentive to invest in needed new generation.

It is possible that more than one generator in a region may have market power at regional demands less than the recorded peak demands in that region. For example, in NSW Macquarie Generation, Delta Energy and Eraring all have market power when regional demand exceeds 12,000-13,000 MW which is well below the highest recorded peak NSW region demand of 14,274 MW recorded in July 2008.

Whilst it is relatively straight forward to assess the precondition for the exercise of market power under normal operation of generation in a region, there are times when outages of other generation plant or interconnectors, allow the exercise of market power at regional demands lower than the normal operating conditions. To prevent the exercise of market power at these other times, there are two alternatives available, viz:

1. For the AER to allow for a "floating" precondition such that AEMO would advise the AER of planned outages of other generation and transmission which would cause the precondition to reduce. For example, if the interconnector between SA and Victoria at Heywood had a planned outage, the AER would declare that the precondition for TIPS would be 2100 MW and use this revised point to control the pricing of TIPS if the regional demand exceeded this new but temporary precondition.
2. There would be no variation of the precondition and exercise of generator market power would be permitted at lower regional demand

levels. When there is a shortage of alternatives to meet demand, exercise of market power at lower levels of regional demand could be considered to be the normal working of the market, and the high prices that might eventuate reflect a true tightening of the supply/demand balance. If this occurs too frequently, then this would highlight the need for new investment. Following this logic, it would appear that to reduce the precondition level is not appropriate.

This proposal considers that the simple approach as embodied in option 2 is preferable and that setting the precondition for a regional demand above which the constraint is applied, should be fixed and only varied when new investment might change the setting of the precondition.

There will be a cost for the AER to assess the market preconditions for each region, but they have already done so for South Australia as part of their normal market overview and monitoring function, so this cost is not likely to have a significant impact on their operating costs.

7.3 The impact of tacit[46] and parallel[47] collusion

Because of the high degree of transparency in the NEM, tacit collusion has been identified as a continuing concern because participants can see what other participants would probably do under a set of given circumstances, providing a strong indication of what can be achieved without direct collusion.

Tacit/parallel collusion could allow generators other than the dominant generator to use the effect of the proposed mitigation approach to impact the spot price when previously they did not have this power. Thus another large generator could reduce its output to force the dominant generator to provide up to its maximum available capacity and by further reduction of output, force on higher priced generators to seek a spike in the spot price.

For example, in SA, when the regional demand exceeds 2500 MW and TIPS is price constrained and must offer all its 1300 MW of capacity at APC, Alinta Energy (with 960 MW from its Flinders assets of Northern, Playford and Osborne power stations) becomes the dominant generator in SA, and is able to exercise market power when the regional demand exceeds ~2900 MW. Knowing that TIPS is price constrained but must offer all of its available capacity and knowing the dispatch criteria of other generation, Alinta can act as if it were the dominant generator and spike the spot price.

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[46] Tacit collusion is the term used where one party takes action based on the expected actions of another party. As the NEM has a high degree of transparency knowledge about one generator's approach to bidding is clearly seen by other generators. With this degree of knowledge, it is not necessary to collude directly.

[47] Parallel collusion is where a second generator could, once the dominant generator is seen by all to be constrained in its price offers, use its market power to set the market price

In NSW, where the three largest generators (Macquarie, Delta and Eraring) are of similar size and have a common owner, each has the ability to manipulate the spot market for significant periods of time. As a result, the issue of tacit collusion is of concern.

The benefits of the NEM transparency outweigh the potential detriments detailed above and therefore should be maintained. It is accepted that tacit and parallel collusion can occur, but unless the regulator has evidence that the second dominant generator in a region has both the opportunity and desire to use its market power, then it is preferable that the potential detriment of tacit and parallel collusion to be ignored unless the AER identifies it to be a problem.

Where the AER identifies that the second most dominant generator has little opportunity to exercise market power (eg as might be the case in SA with Alinta Energy) then there is probably no need for the AER to declare the second largest generator to be covered by this proposal.

However, in the case of NSW where each of the three largest generators all have market power at relatively low regional demands, then the regulator should examine the conditions under which any of the three might be able to manipulate the market and, if needed, to declare more than one dominant generator in the region.

7.4 Would extending the CPT Period have the same effect as the proposal?

The Cumulative Price Threshold (CPT) is to mitigate risk in the NEM when there is an extended period of very high prices over a period. To some extent it does reduce the impact of the exercise of price manipulation because once the CPT is exceeded, an administered price state is imposed until AEMO determines that the causes of the need for a high price no longer apply.

Even with the presence of the CPT, there have been numerous occasions where market power has been exercised, and after the imposition of the administered price ceases (and normal market activity recommences), the conditions for the exercise of market power can still be present and price manipulation can recommence.

A method of achieving a similar effect as the proposed rule change is to use the CPT and this approach might be considered to be less intrusive than the rule change proposed.

To use the CPT would require the value of the CPT to be reduced or for its period of calculation to be extended. The concept of reducing CPT, delinking its value from the market price cap (MPC)[48], or extending the period of its calculation has been debated previously, such as in the 2004 Reliability Panel review of MPC[49], and briefly in the 2008 Reliability Panel review. At each of these reviews, there was little support to make any of these changes but in its submission to the 2008 review the AER stated (page 5)

> "Some respondents to the CRR expressed concern about the practical operation of the CPT and, in particular, its effectiveness as a risk management tool. These concerns were expressed before the extreme pricing events of March 2008. The last time that the design of the CPT was considered in any detail was in December 2003. The Panel at that time considered a number of different aspects of the CPT, including:
>
> - the time period over which the Cumulative Price is accumulated;
> - whether all spot prices that occur during a period should count towards the Cumulative Price, or only those above a certain strike price;
> - the level of the administered price amount.
>
> While the Panel decided against any changes to the design of the CPT during the 2003-04 review, it considered that it was appropriate to regularly review the CPT. Given that recent market events have provided an insight into the operation of the CPT in practice, it may be an appropriate time to reconsider the structure of the CPT as well as its level."

The current CPT arrangement is a 7 day rolling sum of all spot prices, which caps prices to the Administered Price Cap (APC is currently $300/MWh) when the sum exceeds a threshold of $187,500 (was $150,000). Alternatives might include changing the CPT to a fixed three month period (alternative 1) or a three month rolling average (alternative 2) with the CPT equal to the sum of prices above a strike price of (say) $300/MWh rather than the current approach where CPT is the sum of all prices.

The design of a CPT control approach under alternative 1 might consist of a fixed annual quarter time period, a strike price of $300/MWh and a Cumulative Price of $135 000[50]. The level of the administered price amount would remain unchanged at $300/MWh. This CPT approach would allow more than 13 trading prices at the price cap of $10,000 (or 27 at $5 000/MWh, or 135 at $1000/MWh) in an annual quarter before an administered price would be applied.

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[48] Since its inception in 1999, CPT has always been valued at 15 times the MPC and the recent decision to increase MPC to $12,500/MWh still uses the linkage to set CPT.

[49] In this review MPC is called Value of Lost Load (VoLL)

[50] Using this value would capture all outliers and exclude the "normal" prices the market might deliver. $135,000 is the previous CPT of $150,000 averaged on a 7 day rolling less $15,000 which is the weekly cumulative price if an average price of of $45/MWh occurred all the time.

CPT alternative 2 would use the same approach but on a three month rolling basis.

For example, following this approach in South Australia, using volume weighted average prices that occurred in South Australia for the key quarters over the past few years, modelling shows the following results for those quarters assuming a fixed three month CPT arrangement (Alternative 1) and a rolling three month CPT arrangement (Alternative 2) were in place (see table 1).

Table 1 – Specific quarters with and without changes

SA (VWA prices)	Actual	Alternative (1) By quarter	Alternative (2) Rolling 91 days	With rule change[51]
Q1 2008	$242.70	$96.10	$90.84	$51.37
Q1 2009	$160.61	$99.35	$99.35	$98.86
Q4 2009	$133.90	$89.05	$84.97	$38.56
Q1 2010	$133.66	$86.12	$35.15	$53.36

Source: AEMO Data, MEU calculation

The modelling shows that applying CPT over longer periods significantly reduces the average volume weighted prices which would occur in the quarters identified, and applying a rolling 3 month basis has an even greater effect.

For the sake of comparison the outcome per quarter by applying the rule change is also provided – see section 7.5 for the qualifications that applied in the application of the rule change proposal.

If the CPT calculation period was increased to a level that would limit price manipulation, it would also limit the ability of the market to send pricing signals that the market is designed to provide. One of the features of the NEM is that it uses the spot price to signal investment in new generation. There will be periods in the market where there is no price manipulation but high prices driven by scarcity. The CPT approach does not differentiate between high prices caused by manipulation and high prices driven by scarcity. Therefore the use of CPT to limit price manipulation by extending the period of its calculation might have wider reaching and potentially greater negative outcomes than what is sought by this proposal.

The CPT is primarily intended to reduce market risk, whereas this proposal is more about achieving the outcomes of strong competition. There is no doubt that by extending the CPT period, this would result in an outcome that achieves the first element of the proposed rule (ie the benefits from reducing

[51] See section 7.5 for the details of how this calculation has been carried out

market manipulation) but it might also cause a reduction in the market signals indicating scarcity of supply.

Because of the risk that applying a CPT based approach to controlling market manipulation, the MEU considers that its proposed rule change, whilst more interventionist, specifically focuses on controlling market manipulation whilst allowing signals for scarcity to be clearly seen.

7.5 The counterfactual – what would the outcome of this proposal be?

The contention underpinning this proposal is that its implementation will result in an outcome that would reflect a fully competitive market, rather than one which is beset by high prices delivered by exercise of market power.

To assess this, we examine the South Australian regional market over a number of years. As the exercise of market power in SA has been most obvious since the acquisition of TIPS by AGL in 2007, the spot prices in the period before the acquisition (i.e. 2004 to 2006) would provide an indication of what outcomes come from a competitive market. The SA regional prices after 2007 (ie 2008, 2009 and 2010) have been calculated with both the actual market outcomes, and the outcomes that would have occurred had TIPS had its prices constrained to $300/MWh when the region demand exceeded the AER estimated point of 2500 MW where TIPS has market power.

In order to recognise that at times of very high demand, the output of TIPS might have been insufficient to prevent the spot price spiking, and that other generators could have set the spot price (including Angaston which is beneficially operated by AGL but would be expected to bid high prices because it is a peaking plant). To accommodate this, actual prices were used where the regional demand was such that the output of TIPS is insufficient to meet the regional demand, and other generation would have to be dispatched. The MEU calculations therefore demonstrate outcomes that only show the impact of modifying the market power of TIPS, and exclude the impacts of other effects such as very high regional demand, changes in generator mix and fuel mix, and interconnector constraints.

For the purposes of this exercise if TIPS output exceeded 1100 MW (ie ~15% below the highest recorded output from TIPS[52]), then it was assumed that another generator would have set the spot price. The exception to this approach was where TIPS showed that it had the capacity to have provided a higher output than 1100 MW on the day either before or after the high priced period, then the imposed cap was still applied. The result of this approach was that only three half hours in 2007 and one in 2009 required to be modified to

[52] In summer of 2007/08 TIPS output peaked at 1280 MW, in summer 2008/09 at 1276 MW and in summer of 2009/10 at 1249 MW.

reflect the potential other generators might have otherwise been dispatched to meet regional demand, even with TIPS operating at maximum output.

Further, the combined maximum output of TIPS and the other base load generators in SA (Pelican Point, Northern, Playford, and Osborne) provide a total output of some 2700 MW and adding the combined capacity of the interconnectors of some 450 MW results in an ability of base and mid merit generation to provide 3150 MW to the SA demand. For the purposes of this analysis, it was also assumed that if the regional demand exceeds 3100 MW, a peaking generator would have had to be dispatched and the actual price recorded would apply[53].

The outcome of this analysis is detailed in the following table 2.

Table 2 – Annual spot prices with and without the rule change

SA volume weighted annual average spot price, $/MWh	2004	2005	2006	2007	2008	2009
Actual	47.07	36.76	44.68	64.89	92.69	89.84
With cap applied				61.73	43.93	39.10

Source: AEMO data, MEU calculation

The average price for the three years before the acquisition of TIPS by AGL is $43/MWh whereas the average price after the acquisition and applying the price cap, is $52/MWh and the impact of the price cap would have been marginal in 2007[54].

The same exercise has been carried out for the first four months of each year so as to include the effect on four years of operation. The outcome of this analysis is detailed in the following table 3.

[53] This is probably a conservative assumption as there a many examples in the SA region when demand has exceeded this amount, but the spot price lies below $300/MWh. For example at 17.30 on 28 January 09 the regional demand was 3276 (only 55 MW or 1.5% below the highest ever peak demand of 3331 MW recorded in SA) the spot price was $244/MWh and TIPS had nominally up to 200 MW of spare capacity still available for dispatch.

[54] 2007 year data needs to be treated with care because the transfer of ownership of TIPS to AGL did not occur until after the summer of 2006/07, and much of the high regional price was effectively "imported" from the eastern states which were undergoing price hikes because of drought conditions. The impact of the drought is shown in appendix 2, which shows that annual average volume weighted prices in Queensland, NSW and Victoria are higher than in SA, implying that dispatch of SA generators was in part needed to export electricity.

Table 3 – Spot prices for the first four months of a year with and without the rule change

SA volume weighted first four months average spot price, $/MWh	2004	2005	2006	2007	2008	2009[55]	2010
Actual	56.64	32.87	51.17	69.64	197.44	132.55	110.46
With cap applied				62.68	51.45	84.89	48.40

Source: AEMO data, MEU calculation

The average price for the first four months of each year for the three years before the acquisition of TIPS by AGL is $47/MWh whereas the average price after the acquisition and applying the price cap, is $61/MWh and the impact of the price cap would have been comparatively marginal in 2007.

What is clear from the analysis is that the 2008, 2009 and 2010 spot prices after applying the price cap to TIPS, are quite closely aligned to prices that applied before AGL acquired TIPS, recognising that exogenous impacts would have caused some variations but reflecting similar outcomes seen in the eastern states (see appendix 2).

The conclusion that can be drawn from this analysis is that the proposal will result in outcomes that more closely align with the outcomes expected of a competitive market.

However, it is also quite clear that peaking generation previously dispatched by TIPS economically withdrawing its capacity will not be dispatched as frequently as they have been, usually when regional demand exceeded ~2500 MW but are more likely to be dispatched when regional demand approaches ~3100 MW. This means that SA peaking generators will be dispatched much less frequently, but sufficiently often to warrant the price offered to the market.

In the last three summers, the SA half hour regional demand exceeded 3100 MW for some 18 hours. Peaking generation would have had to be dispatched for this amount of time and probably for much longer when issues of fast start, intra-regional constraints and base and mid merit generation outages occurred. As the price for these periods was near MPC, the amount of time and the prices offered would provide the income needed for such plant based on the derivation of MPC[56].

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[55] The prices for the first four months of 2009 are heavily influenced by the very high peak demands and load shedding experienced on 28 January when the highest regional peak demand of 3331 MW was recorded and on 29 January when load shedding was required.

[56] MPC is effectively calculated as the price a peaking generator needs to receive for power if it is only dispatched for 6-8 hours each year.

7.6 Potential areas for derogations

7.6.1 NSW Gentrader bundles

NSW is in the process of effectively “selling its generators without selling them”. To achieve this it has developed a unique approach whereby some of the output of its generators is sold to a trader, called a gentrader. The details of the actual final structure of the NSW generation market are still unclear, but the final arrangement might lead to an effective increase in the number of generators notionally operating in the NSW region.

Under this proposed rule change, in the absence of the gentrader model, it might be that AER would denote the three largest generators in the region (Macquarie, Delta and Eraring) as having market power at levels less than the maximum regional demand, and would therefore be declared as dominant generators by the AER.

It is possible that the introduction of the gentrader model might increase competition as a result of the introduction of the gentraders or have a significant reduction in the output controlled by any of the three generators and, as a result, lead to an outcome whereby none of the generators or gentraders have market power.

If this occurs, the AER would determine that no generators or gentraders have market power at expected regional demands, and no dominant generator would be declared.

7.6.2 Tasmania is a special case

Generation and demand in Tasmania is such that Hydro Tasmania (HT) – a government owned generator – always has market power as the combined output of all other sources of generation in Tasmania is almost always less than the actual demand.

Under our rule change HT would always be constrained to offer its output at APC or lower. However, for a third of the time, Tasmania exports power to Victoria via Basslink, and HT (which effectively controls Basslink) uses these exports to balance the costs of power imports and the cost of Basslink. Therefore to constrain HT to APC at all times, would provide an unintended benefit to Victorian consumers, and could have the outcome of muting investment signals for new generation investment in Victoria[57].

The Tasmanian government has required HT to provide contracts to Aurora Energy (the Tasmanian government owned retailer) at pre-determined prices for Aurora to supply to all Tasmanian non-contestable customers to protect Aurora from the risks inherent in retailing from market pricing volatility. This government requirement does not protect larger (contestable) customers from HT using its market power to set contract and spot prices in Tasmania.

Notwithstanding the risks facing contestable customers in Tasmania, there is a need to insulate HT from the imposition of this rule change, as to have HT constrained by the proposed rule will cause problems for the market more generally, especially in relation to providing exports to Victoria at appropriate prices.

Our proposed rule change sees that there needs to be a derogation in relation to Hydro Tasmania which would exclude HT from having to comply with the new rule.

To overcome the impact of this derogation, contestable consumers in Tasmania would have to seek government intervention in relation to HT pricing so that the same outcome that would result from the application of the rule will flow through to Tasmanian contestable consumers, much the same as the government has already done in the case of non-contestable customers. As the Tasmanian government owns HT, this approach to controlling HT as the dominant generator is achievable.

The MEU has considered what approaches might result achieve the necessary protection for Tasmanian contestable customers. The MEU notes that the Tasmanian electricity market has a very close relationship to the Victorian electricity market. One solution to providing Tasmanian contestable customers and HT with a competitive outcome, would be for these customers to be provided with power from HT at contract prices no worse than those based on Victorian electricity spot prices.

The need for such a derogation is that due to the control HT has over the Tasmanian wholesale contract market there is a need for a surrogate wholesale market for Tasmania to allow HT to bid appropriately into the Victorian market.

[57] The importance of Basslink and HT supplies to Victoria cannot be understated. For example in January 2009, the failure of Basslink resulted in load shedding in Victoria and SA when these regions were experiencing very high demands

8. Analysis of benefits and detriments of the proposal

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Generally there is agreement in overseas jurisdictions that generator market power can be a problem that leads to anti-competitive outcomes and causes economic damage.

The MEU considers there are further reasons why it needs to be addressed.

8.1 Benefits

8.1.1 It allows the market design to operate as intended

The rule change proposal will result in the basic architectural concept of the electricity market being achieved. The market design basic assumption is that generation will be dispatched in merit order of marginal cost which is the most economically efficient dispatch profile and is the basic assumption behind the calculations to set the market price cap (MPC) or value of lost Load (VoLL)[58].

Whilst competition should result in generators bidding in accordance with each generator's marginal cost, if a generator has market power then it can use this market power to allow it to still be dispatched but at a higher price than its marginal cost.

The major benefit of this proposal is that it will prevent a generator from using its market power to set prices well in excess of its marginal cost effectively abrogating the fundamental design feature of the market.

8.1.2 Volatility and uncertainty reduces

One of the features of a market manipulated by a dominant generator is that the volatility of the market increases dramatically and with greater severity, which creates an artificially inflated risk of operating in the market.

In appendix 2, there are tables showing the frequency and severity of volatility in the different regional markets. A comparison of the outcomes in the different regions, shows that since AGL acquired TIPS in 2007, the market volatility and severity in SA has increased dramatically. When the SA markets are compared to other regional markets, the step

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[58] The calculation of MPC is predicated on calculating the revenue required for the last generator (ie with the highest marginal cost) needed for that generator to operate for the few hours each year at times of maximum demand. MPC at $12,500/MWh implies that the last generator to be dispatched would operate only for 7-8 hours each year and its bid price of MPC for these few hours each year would recover the necessary revenue it requires to be commercially viable.

increases in SA are not matched by equivalent increases in other regions.

Increasing frequency and severity of volatility (ie allowing unfettered exercise of generator market power) results in a number of negative outcomes:

- Generators tend to contract forward capacity less, as the consequence of an unplanned outage becomes greater. To offset this they keep more plant available back up their contracted position, reducing the amount available for contract. Alternatively they contract externally for backup, and thereby increase the cost of generation[59].
- As volatility increases (especially volatility created by market manipulation), lenders to those seeking to invest see an increased risk in recovery of the capital lent. To offset this, lenders seek a higher debt margin to accommodate the increased risk
- As retailers are exposed to the spot market for any unprotected volume risk of their portfolio, they use the futures market or build their own peaking generation to minimise the risk. Counterparties offering coverage of this risk face costs and risk to provide this commitment risk coverage, causing an overall increase in the retail risk management costs
- The secondary market is negatively impacted as increased volatility makes it less able to forecast future needs and prices
- Retailers face increased prudential costs due to the impact of the volatility as it causes a significant increase in the cost of electricity and therefore an increase in the prudential requirements for participants.
- Retailers not able to get risk coverage and/or unable to carry the increased prudential costs, exit the market reducing retail competition
- Industrial and commercial consumers pass this increased cost into their markets, increasing costs to the wider population. Those not able to accept the increased costs, either exit their markets[60] or take spot exposure and manage the volatility by reducing demand when high prices apply. As electricity demand is relatively inelastic, few consumers are able manage the risk of volatility by modifying their demand in the time frames when prices and demand are high.

[59] Recently the NSW government sought to overcome this risk by proposing a co-insurance scheme between the government-owned generators. In its draft decision, the ACCC decided not to allow this due to its uncompetitive nature.

[60] Many industrial consumers have advised that increased costs (including energy costs) have been a core reason for them exiting the Australian markets

As electricity supply is an essential input to every walk of life and every business, increased volatility has an overall dampening impact on downstream investment. Where this volatility is artificial (such as arises out of market manipulation) the impact on the wider economy is severe. Those charged with managing the electricity market need to recognise the impact of allowing artificial cost impacts are wide spread and significant.

As a result of reducing volatility, uncertainty reduces. Uncertainty in a market increases costs as participants attempt to insulate themselves from the uncertainty. Uncertainty about a market has a number of outcomes including:

- Concern whether the apparent market signals are a true reflection of the fundamentals of a properly operating market
- Whether the dominant generator will exercise its market power (or not) to increase prices.
- What the potential is for the market to be sent into an administered price state because the cumulative price threshold (CPT) might be exceeded

The National Electricity Law Objective requires that the NEM is to be considered in terms of promoting[61]:

> "...efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

Of these, price is the element of the objective which is most impacted by unnecessary volatility, and therefore must be assessed if this volatility is caused by artificial means.

Offsetting the impact of price, the reliability of the market is also important as volatility is one of the signals for investment in new generation. In terms of periods of high demand, volatility provides a need to contract for the peaks in demand. Volatility and uncertainty tends to create an environment where risk is higher and this risk can be managed by building new peaking generation. Therefore in one way,

[61] National Electricity Law section 7

volatility can be considered to provide an incentive for new generation investment.

Whilst investment in peaking generation might be incentivised by increased volatility, base and mid merit generation investment is more likely to be dis-incentivised by increasing volatility (especially artificially generated volatility) as discussed in section 8.2 below.

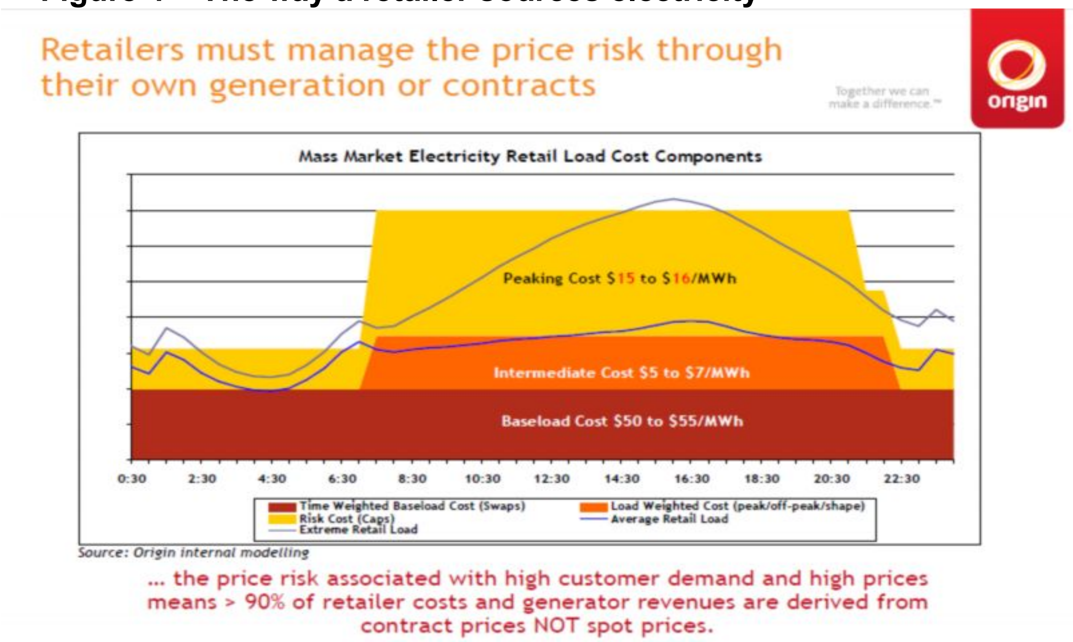
What needs to be assessed in regard to increased volatility is a balance between the spot price reflecting marginal costs and signals to invest in new generation.

8.1.3 Competition increases in retailing

Retailers are an essential intermediary in the NEM. They provide expertise in managing the risk that the NEM imposes; they aggregate load from a number of users and by doing so minimise the risk inherent in being a single user with a variable demand, and they contract for firm load providing generators with certainty of future cash flow.

It is impossible for a retailer to match its actual demand profile exactly with its portfolio of contracts and still be competitive in the market. Because of this all retailers have some exposure to the spot market. This can be typified in the following figure 4 provided by Origin Energy – a large retailer with a large portfolio of gas supplies and generation based on gas.

Figure 4 – The way a retailer sources electricity



Source: Origin Energy presentation to Reliability Panel, Feb 2010

This shows that although a retailer's portfolio of contracts covers the bulk of the risk exposure they face, there is a small proportion of their load that is not protected and is exposed to the spot price. Although this risk exposure to the spot market can be mitigated by careful assessment of the forecast demand, if by the exercise of market power a generator can cause higher spot prices generation to be dispatched (and so artificially increase the spot price), then this increases the risk a retailer faces in respect to its portfolio.

For retailers to provide the services they do, they need to have access to firm forward contracts, access to a range of hedging contracts at reasonable prices and a reasonable expectation that the market will operate as intended by its design in order to manage their portfolios. Failing this availability of these tools, retailers have the option to build their own generation to cover their risk or exit the market.

For example, in South Australia, as a result of the excessive risk exhibited in this regional market resulting from the operation of TIPS, some retailers (eg Origin Energy with the expansion of its Quarantine power station) have increased their portfolio of peaking generation to provide hedging, whilst others (eg Aurora Energy) have exited the market as they cannot obtain adequate contracts to manage the increased costs and risks they face by providing retail offerings.

Jackgreen executive chairman Greg Martin commented when Jackgreen went into voluntary administration[62]:

> "[The electricity market] this is an extremely difficult business for a small, tier two retailer to play in. The working capital and prudential requirements of the electricity markets in Australia have clearly become such that size and substantial financial backing are required to operate in the market…increasingly this will become a game for larger, well-capitalised businesses".

This clearly highlights that the more volatile the market, the riskier and more expensive it becomes for retailers. Retailers exiting the market reduce competition.

In its submission to the Reliability Panel in February 2010, Origin also points out that the more volatile the market the higher the prudential and risk capital costs are to retailers. As a result of the high priced events in the NEM in December 2009 and the exit of Jackgreen, Origin's

[62] Luke Forrestal, "Jackgreen too small to play: chairman", Australian Financial Review, 21 December 2009, p.36

prudential requirements increased by 30% (page 10). Origin goes on to add[63]:

> "In Origin's experience, on some occasions the domestic bank market has already hit its natural industry ceiling for providing prudential guarantees for electricity retailers."

If the risks inherent in the electricity are already seemingly too high for retailers to secure bank guarantees to cover their prudential requirements, then there is a concern. When these risks are increased by overt market manipulation and not by the normal process of dispatch, then there is clear evidence that action must be taken to reduce unnecessary risks.

8.1.4 Prices for consumers will reduce

Consumers will benefit because the price to buy electricity from the market will reduce to the least cost, which is consistent with the National Electricity Objective.

A direct benefit of reducing prices to economic levels is that consumers have much clearer signals on which to base their investments. There is a strong multiplier effect on downstream investment due to prices for electricity; lower prices result in significant downstream investment whereas higher prices stultify downstream investment. High prices are a result of manipulation of the electricity market can only be to the detriment of downstream investment. For example, currently downstream investment in SA by consumers[64] is being constrained by the inflated contract prices resulting from the exercise of market power of TIPS.

Additionally some consumers are deliberately reducing their output at times of high spot prices. This means that not only are their investments are lying idle for periods of time, but lost productive time and increased wastage occur. Their decision to operate on the spot market and reduce demand at times of high electricity prices might be considered to be an appropriate response to the electricity market needs when there is a scarcity of supply, but it is overall economically inefficient when the high prices are driven by the exercise of market power.

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[63] Origin submission to Reliability Panel February 20101 page 10
[64] This point is made clearly by the AER and AEMO who in the final decision in regard to the SA EDPR for ETSA Utilities is forecasting an overall reduction of electricity sales in the next 5 years.

A decision for consumers to reduce output or shut down has the effect of reducing the return on investment in the downstream markets. Allowing a generator to exercise its market power does not make the electricity market more efficient (but it does make it more profitable for the generator), increases inefficiency downstream, thereby impacting national prosperity.

By using its market power, the dominant generator has the potential to increase its revenue immediately. If a generator is heavily contracted, spiking the spot price is likely to result in only a modest revenue improvement, but as the amount of forward contracting of output decreases, so the incentive to spike the price whenever possible, increases.

From a consumer viewpoint, allowing a dominant generator obtain a benefit from spiking the spot price, creates an environment where retailers increase their costs to provide risk management to make themselves less susceptible to the volatility. Similarly other generators likewise see increased risks and accordingly increase their price offerings. Over time these factors combine to result in higher contract price offers to consumers.

For example, in the SA region, since the acquisition of TIPS by AGL in 2007, consumers have seen the contract offerings from retailers increase by some 50% and at the same time see the numbers of retailers prepared to offer, nearly halve. Other than the way TIPS has operated, there have been no significant other changes in the SA regional market to cause such large increases. In comparison, other regions have not seen changes as large as this in their markets[65], implying the cause of the changes seen in SA is regionally based.

To quantify the impact of the changes in retail price offerings, the average spot price in SA for the six years 2001 to 2006 was less than \$40/MWh and typical retail prices were 10% higher. Since TIPS began exercising its market power the average spot price has increased to over \$60/MWh and this was reflected in a 50% increase seen in retail price offerings. This is despite there being only a very small increase of some 2% pa increase in peak demand in the nine years between 2001 and 2009.

As the SA regional market demand is some 13.5 TWh pa, the impact of the increase of ~\$20/MWh seen in both the retail and spot markets means there has been a transfer of wealth from consumers to

[65] This is especially obvious when the NEM wide impact on spot prices of the drought in 2007 is excluded.

generators of an additional $270m per annum for each of the past three years.

In section 7.5 above, it was shown how eliminating the exercise of market power by TIPS resulted in a significant reduction in the regional reference prices in 2008, 2009 and 2010, and resulted in pricing being more consistent with SA regional prices prior to the acquisition of TIPS by AGL, and reflecting consistency with trends seen in other regions in the same time periods..

The reduction in SA regional reference prices to these levels results in significant saving to consumers.

8.1.5 Liquidity in the contract market improves

The MEU view is that investment signals for new generation will be impacted by a volatile market and these views are more expansively explained in section 8.2.1 below. But in addition to this impact, it has been seen that the liquidity of the contract market is also impacted. As Origin Energy explained in its submission to the Reliability Panel on 24 February 2010 (page 5):

> "...generators tend to contract only a certain proportion of their available capacity, principally to cover themselves against outage risk caused either by transmission or equipment failures (the risk that a generator is required to purchase from a high spot market to fund their contract obligations)."

If generators see a greater risk in the market, their response will be to reduce the amount they seek to contract and increase the amount of generation they dispatch in the spot market to provide themselves with a greater physical hedge against the potential of an outage and to maximise their revenue they might get, by the dominant generator spiking the spot price.

When the dominant generator spikes the spot price, the overall rewards to generators increase and this in turn encourages generators to contract forward less output both from the financial rewards and to reduce the financial risks of a contracted generator failing.

If any generator considers it will get a larger financial reward by not contracting its output and "playing the spot market" because it knows the dominant generator will exercise market power, then a counterparty will have to agree to a higher contract price to recompense the generator for not "playing the spot market".

What has been seen in the SA region is that retailers have had less ability to secure contract offers from generators and as a result have decided to reduce the amount of retail offerings they make. Large consumers with attractive load profiles have been regularly advised by many retailers that the retailer is either not prepared to offer, or is unable to make an offer, to such large consumers.

This reduction in competition and associated increase in prices is not in the "...long term interests of consumers".

8.1.6 Liquidity in the futures market improves

The futures market is intended to provide the ability of market participants to hedge their risk against future market price movements, where such hedging cannot be readily achieved in the contract market.

A highly volatile spot market where this volatility can be attributed directly to exercise of generator market power leads to two outcomes – prices that are offered are excessively high to address the potential risks, and fewer generators are prepared to offer as their capacity is dedicated to hedging their own wholesale offerings.

Excessive high prices and few price offerings lead to a reduction in liquidity in the futures market. For example, the market for SA futures is quite modest, compared to markets where there is less volatility and more certainty.

A very liquid futures market is a clear marker as to whether a market is seen as viable or not.

8.2 Potential detriments

8.2.1 Dampening generation investment signals

It is recognised the proposal signifies a significant change to the current NEM market design, which relies on energy only prices to provide returns on investment for existing generators, and to signal new investment.

The main (perhaps the only) reason not to implement a control on exercise of generator market power, is that by doing so, there will be a reduction in generation investment.

The NEM design assumes that investment in new generation will be encouraged by providing accurate market price signals, and the only price signals seen by all participants (existing and intending) are the spot prices. So, in theory, the spot market is intended to provide the signals for new investment, especially as it has been seen that retail contract prices do follow the spot market, although with a lag.

This observation is supported by the actions of the Reliability Panel (RP) of the AEMC and the AEMC itself, which have been a consistent supporter of the need to increase the market price cap (MPC) as a means of encouraging generation investment and thereby maintaining the reliability standard. In fact the main tool the NER provides the RP to maintain reliability, is the setting of the MPC[66].

In practice, it is the contract market that actually provides the incentive for new generation investment. This point is made very clear by Origin Energy in its presentation to the Reliability Panel in its response to the 2010 review of market settings. Origin comments (page 3):

> "The consequential variability and volatility of spot prices means that investment in new generation is driven by the contract market rather than the spot market. Both generators and retailers have incentives to fix their future cashflows in a volatile market through contracting. Importantly, financial institutions are unlikely to provide the finance needed to underpin investment without the security of such contracts.
>
> For retailers, the desire to contract arises because being short in a market with extreme prices can quickly lead to bankruptcy."

As a result of its considerations, Origin observed that further increasing the MPC would not lead to more investment in generation. Origin also observed that a minimum level of MPC is needed to provide generation investment, but the current level of $10,000/MWh was seen to be adequate for this purpose.

What this means is that at the current levels of MPC in the NEM, Origin considers the contract market is the main driver for investment, not the spot price signals. This supports the MEU view that continuing to allow excessively high price signals that are the result of market manipulation (and not a result of scarcity) does little to drive new investment in generation. That generation investment does occur in other jurisdictions even when constraints are applied to the exercise of market power, when, also supports Origin's basic contention.

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[66] Reserve Trader is a tool available to AEMO to maintain reliability

8.2.1.1 Other jurisdictions have imposed constraints such as this but not shown a reduction in generator investment

As the report in appendix 4(a) and 4(b) on addressing generator market power in overseas jurisdictions shows, overseas regulators do not see there is a net benefit in allowing the exercise of unfettered generator market power. Those overseas regulators have devoted considered effort to develop rules which prevent market manipulation, whether this has been achieved by compulsory divestment (as in the UK), pricing controls (as by NYISO), or punishment (as by ERCOT).

Notwithstanding these controls or risks, sufficient investment in generation has occurred in these other jurisdictions although, as the report highlights, not all of these jurisdictions operate with an energy only market[67].

8.2.1.2 A balance is required between market power and providing accurate signalling

By far the most preferred control on pricing is one driven by competition. When there is competition, the dominant generator in a region is effectively constrained to offer its energy at its short run marginal cost (SRMC) or risk not being dispatched. When the dominant generator is fully dispatched, and higher cost generation is scheduled on, the dominant generator receives payment for its output at the rate set by subsequently dispatched generators.

Under these circumstances, there is no concern that the price signals provided by the market will be insufficient to incentivise new investment as this is the basic concept of the market design. Therefore there is needed to be a balance between what a reasonable dispatch price for the dominant generator is and what it can achieve when it has market power.

This proposal recognises that there is a need to ensure that price signals for generation investment are still strong. Already in the NEM, there are instances where the market can limit the dispatch price of a generator needed to supply the market. The most obvious and apposite is the administered price cap (APC) that applies under certain circumstances.

[67] It is recognised that in a capacity market there are requirements on generators to be available for dispatch when needed, and if they are not then the capacity payments due to a generator are at risk.

The APC in the NEM is currently $300/MWh and this level was established in 2008 by the AEMC. In its determination[68] the AEMC observed (page vii)

> "The Commission considers the APC level should be sufficiently low to mitigate the risk of a systemic financial collapse and sufficiently high not to distort the incentive for supplying electricity during an extreme market event when the APC is triggered. In addition, the Commission considers the APC level should be sufficiently high so that the expected frequency and magnitude of compensation claims are kept to the minimum.
>
> The Commission considers an APC level of $300/MWh is adequate in achieving a balance between the competing objectives.
>
> This APC level is significantly higher than the short run marginal costs (SRMCs) of most generators in the NEM. The APC level is therefore effective in minimising the distortion of the incentive for supply participation during an extreme market event, when the APC is triggered.
>
> An APC level of $300/MWh is likely to mitigate the frequency and magnitude of compensation because: (a) the APC level is not significantly lower than the highest estimated SRMC in the NEM; and (b) the total generation capacity, with estimated SRMCs above the APC level, is assessed by the Commission to be minor compared to the total generation capacity in the NEM."

Our proposal highlights that the only generator constrained in its pricing to the APC will be the dominant generator; that is all generators will be dispatched in merit order under normal conditions, and only when the dominant generator has the potential to manipulate the spot price, will it be constrained to offer at a price cap of the APC.

As the dominant generator in any region will be a large base or mid merit generator, applying the APC as an upper limit on its pricing, will still provide it with revenue more than 6 times its long run marginal cost and even higher on its SRMC[69]. The AEMC has

[68] AEMC Determination of Schedule for the Administered Price Cap Final Report, 20 May 2008
[69] It is possible that the SRMC for a mid merit generator might exceed the current APC level of $300/MWh, but if this was to occur, then it is expected that the AEMC would have revised the level of APC to ensure that it was higher than the SRMC of most generators operating in the

identified that if intervention is required in the market then an APC of $300/MWh is more than almost every generator requires in order to receive an adequate return on its investment.

Being limited to such a high multiple of its basic operational needs, still provides a much better return than if it were constrained by competition.

Thus the proposal does not reduce the signals for generation investment than would occur under a fully competitive market.

8.2.1.3 All other generation in a region is not affected by the change

This proposal only imposes a constraint (and only then when it has the ability to exercise market power) on the dominant generator. All other generators are able to offer prices to suit their revenue expectations. As the proposal attempts to replicate the expectation that the dominant generator will be dispatched as would be expected, a new investor in generation will see that its new plant will be dispatched in merit order and therefore the investor will be able to identify a realistic dispatch profile for the new plant, rather than one which be impacted by market manipulation. This increases the certainty the new investor can make decisions based on reality.

8.2.1.4 The proposal reflects true competition

As noted above, constraining the dominant generator to offer prices that are higher than would occur under a strongly competitive market, cannot mute generation investment signals below that which would occur if there was no ability to exercise market power. This is effectively the conclusion that overseas regulators have reached when they decided that explicit constraints on market power are essential if the benefits of competition are to be enjoyed by consumers.

8.2.2 The change will have a market price impact – will this impact investment in generation?

Introducing a bidding restriction such as is proposed might deter investment by dampening price signals for periods when there is high demand.

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market. This is a prime issue that the AEMC addressed in its calculation of the current level of APC.

Reducing the spot price at times of higher demand when the spot price is artificially increased, would reduce returns for existing peaking plant. This might diminish the business case for future investment, but if this occurs then it is an artificially driven return that would not occur if there was no dominant generator. The normal dispatch profile is one where the base and mid merit generation is dispatched ahead of peaking plant as this is the least cost approach. In theory, the NEM design intends that lower marginal cost plant should be dispatched before higher marginal cost plant. If market power encourages a different outcome, then this is an unintended distortion of the market.

A new investor would view, with concern, apparent price signals which are clearly the outcome of market manipulation, and would definitely query whether these signals are those which can be relied upon for such a high cost and long term investment.

Another aspect is that if the dominant generator (such as TIPS in the SA region) is compelled to run all its capacity at times of high demand, this will displace peak capacity from the bid stack for larger periods of time than is the current outcome when the dominant generator manipulates the market. Whilst peaking plant does play an important role in the NEM generation mix, it is not appropriate that peaking plant should be displacing lower marginal cost plant in the dispatch order.

On balance, removing the ability of one or more generators in a region from being able to manipulate the market, provides greater certainty for new generation investors that the market signals are a true reflection of the market needs, rather than an inflated value which could disappear at some time in the future.

On this basis, the MEU concludes that, as the proposed rule change will only result in the market reflecting true competition, it is unlikely to significantly reduce the incentive to build new capacity.

8.2.3 This change requires regulatory intervention

Regulatory intervention, such as imposing a bidding restriction, has the potential to create uncertainty for potential investors. At the same time, potential investors in generation plant see obvious manipulation of the market also creates uncertainty. Given the long life of a generation asset, investment is more attractive if the regulatory playing field, upon which the initial business case is based, is unlikely to change. However, regulatory certainty (ie not changing the NER) should not be considered to prevent changes which result in an improvement (or reduction of detriment) to the market.

A stable market design is an essential element or any market (such as the NEM with its energy only market structure), but a market which can be seen to be so easily manipulated as the NEM, which relies on price signals and the associated market driven investment, must be considered likely to be changed at some time. It would be disconcerting that an obviously incorrect rule is not changed because changing it would create uncertainty.

Market manipulation is unacceptable in terms of competition. To allow anti-competitive actions to continue purely because of a concern of regulatory risk, is looking at the problem from the wrong direction. Market manipulation is inherently anti-competitive, so to allow it to occur there needs to be a clear demonstration that there is a net benefit to permit its continued use.

Further, because market manipulation is seen as anti-competitive, there will be an expectation of change if the manipulation gets to a level which causes significant distortion. Not changing the NER will create more uncertainty as investors might well wait for a rule change to eliminate such an easy ability to manipulate the market.

9. Suggested draft wording for the proposed rules change

The MEU considers that the following wording changes to the NEL would achieve the requirements of the proposed rule change

Add to NEL part 6, section 58(c)

> In the case of a breach of rules, the AER has the same powers as the ACCC when the ACCC is prosecuting a breach of the Trade Practices Act 1974, in relation to sections 46, 47 and 48 of the TPA.

[The purpose of this clause is to provide the AER with the same powers as the ACCC has in its investigations of breaches of the TPA. As the exercise of generator market power has the same financial outcome for the party with the market power as competition issues under the TPA, it is appropriate the AER has the same powers to investigate and penalise a transgressor]

The MEU considers the following wording changes to the NER would achieve the requirements of the proposed rule change.

Add clause 3.1.4(a)(10)

> Enhancing competitive outcomes in the spot market by preventing a generator from using its market power to manipulate the spot price in a region.

[The rationale for this clause is to introduce a statement of purpose to reduce the exercise of generator market power]

Add to clause 3.1.4(b)

> However it is recognised that the Trade practices Act, 1974 does not prevent a generator in the electricity market from using its market power to manipulate the spot price, because this does not reduce competition which is the focus of the Trade Practices Act. These rules therefore aim to limit the ability of a generator to exercise its market power when the regional demand is at a level where a generator has the potential and economic interest to exercise its market power.

[The purpose of this clause is to highlight that the TPA does not prevent the exercise of market power to increase profits, but acts to prevent excess profit making by addressing reduction of competition]

Add to clause 3.8.1(d)

The dispatch algorithm must:

(i) Provide an alarm that if, when the regional demand exceeds the level determined in clause 3.8.2(f), the dominant generator prices its output higher than the Administered Price Cap. AEMO must advise both the dominant generator and the AER that the dominant generator is not complying with clause 3.8.6(a)(5).

(ii) Insert a price no more than the Administered Price Cap into the algorithm to represent the offer a dominant generator is required to make when the regional demand exceeds the level determined in clause 3.8.2(f)

[The purpose of this clause is to ensure that any potential abuse of market power is minimised and that the integrity of the market is maintained for consumers]

Add clause 3.8.2(f)

The AER must assess the generation in each region to identify which generators have the ability to exercise market power and at what level of regional demand. If this level of demand is less than the forecast regional demand then those generators will be determined to be dominant generators.

The AER must develop guidelines as to how it will determine if a generator is a dominant generator. These guidelines will include the following features:

- The AER shall assess each region each year in March of each year to identify if there is a dominant generator in a region
- Generator output will be determined based on a number of factors, including nameplate rating, actual maximum recorded output of the combined generating plants under the control of the generating company in the previous four years, and the amount of generation advised to AEMO in its assessment of its EAAP[70] for the period.
- The dominant generator must give an acceptable explanation to the AER why the GELF[71] that it advises to AEMO as part of the development of the EAAP does not reflect the maximum actual recorded capacity.
- Generation plant will be the output of generating plant owned by the generating company as well as any generation over which the generator has dispatch control

[70] Energy Adequacy Assessment Projection
[71] Generator Energy Limitation Frameworks

- Inflows on interconnectors should be assessed in terms of likely congestion limiting flows, nominal capacity and actual transfers measured over the previous four years
- The forecast regional demand shall be determined by AEMO at the 10% Probability of Exceedence (PoE)
- A dominant generator shall only be declared where the level of demand where it can exercise market power is less than the forecast regional demand for the next high demand period.

The AER will declare generators which have market power in a region, and at what level of regional demand they have market power. The AER declaration shall be made each 1 April and the declaration shall force for the ensuing twelve month period.

Once the AER has determined which generators have market power at what regional levels, it shall publish this information and advise the AEMO of its decisions. AEMO will use this information to modify the dispatch algorithm as required by clause 3.8.1(d)

[The purpose of this clause is to ensure the AER has a transparent approach to its determinations of which generator has market power and when it is able to use it, and that the decision is made public and provided to AEMO so that it can modify the dispatch algorithm]

Add clause 3.8.2(g)

The AER shall monitor regional demands, and shall review:

(1) The pricing offered by dominant generators when the regional demand exceeds the level at which the AER has determined they have market power
(2) The amount of output the dominant generator provides when it is considered to have market power.

If the AER considers that the dominant generator has not provided pricing as required by rule 3.8.6(a)(5) or the dominant generator has not offered the maximum available capacity the dominant generator is considered to have, then the AER shall carryout an investigation to determine why the dominant generator did not price its output as required, or offer its maximum available capacity.

For the assessment of available generation capacity, the AER will consider the amount of capacity offered by the dominant generator in the periods before and after the period when the dominant generator is considered to have market power.

The AER shall carryout such an investigation as if it were the ACCC investigating a breach of the Trade Practices Act 1974, in relation to sections 46, 47 and 48 of the TPA.

In setting penalties, the AER shall apply the same approach as the ACCC would do if it found a breach of the TPA.

[This sets out the powers of the AER to enforce the Rules regarding market power]

Add clause 3.8.6(a)(5)

If a scheduled generator is declared under clause 3.8.2(f) to be a dominant generator in a region then when the regional power demand reaches the level determined under clause 3.8.2(f) then a dominant generator must:

(i) Offer all of its output at a price no more than the Administered Price Cap (APC)
(ii) Offer all of its available generation capacity to the market.

[The purpose of this clause is to require the generator with market power to comply with the AER determination in relation to when it has market power. If a generator complies with the rule, then there is no risk that it will be investigated nor have penalties applied by the AER]

Add clause 3.13.7(c1)

The AER must prepare and publish a report annually which provides the determination of which generators are classed as dominant generators and under what conditions. The AER shall include in the report details of:

(1) All times when a dominant generator did not offer pricing conforming with clause 3.8.6(a)(5)(i) and was price constrained by the AEMO dispatch algorithm
(2) When and to what extent the dominant generator did not offer all of its available capacity to the market conforming with clause 3.8.6(a)(5)(ii)
(3) What actions the AER took and the outcomes of these actions caused as a result of any investigations made in accordance with clause 3.8.2(g)

[The purpose of this clause is to require the AER to provide information to the market about the need to apply sanctions as a result of this rule change]

Appendix 1

Analysis of the ex post and ex ante options

1. ex post option

- An ex post approach would identify if each generator has operated within its common envelope of operation in order to identify whether
  - There has been an exercise of market power
  - What is the cost premium that the exercise of market power has caused
  - An ex post approach is used by the Texas regulator ERCOT which also supervises the Texan energy only market
- Once there is determined there may be a case of exercise of market power, the AER would assess the bidding patterns of every generator at the time of potential exercise of market power in order to identify which generator(s) were exercising market power. Such assessments might include
  - The pricing pattern of and amount of generation offered by each generator for the 12 hours before and the 12 hours after the high price event
  - The pricing pattern of and the amount of generation offered by every generator over the previous and subsequent three month periods
  - The pricing pattern of and the amount of generation offered by every generator over the same month(s) in the previous five years as the period being investigated
  - The impact of any other changes in the market that might have influenced a change in pricing approach from the historic norms (eg generation recently commissioned or decommissioned, the increase or decrease in transmission capability impacting specific generators or interconnection, the impacts of weather on intermittent generation)
- Such indicators for further analysis might be
  - The marginal price is >$5000/MWh
  - The marginal price was set by a generator other than a generator which normally provides occasional supply into the NEM
  - The average spot price over a month is greater than the same month in previous years by more than (say) 25% above the average of the same months in the previous few years
  - The average spot price over a quarter is greater than the same quarter in previous years by more than (say) 15% above the average of the same quarters in previous years
  - Bidding and rebidding was carried out in such a way that despite the presence of high spot prices, the cumulative price was maintained at a level close to but not exceeding the CPT
  - What are the variations in the price stack that vary from the traditional concept that base load generation is dispatched first, followed by intermediate ranked generation, and finally by peak generation with lower cost fuels (eg gas) being dispatched ahead of higher cost fuels (eg oil).
- If the analysis indicates that a generator may have exercised market power, it should have the opportunity to comment to the regulator on the allegation and give reasons why it changed its bidding approach to increase the spot price. End users should also have the opportunity to comment on the impact they experienced of the apparent exercise of market power.

- The AER should develop a spot price scenario that would have applied if the generators being examined had priced their generation based on historic and subsequent approaches to pricing, based on the demand available to the generator at the time. This would create a potential cost to the market of the exercise of the market power by assessing how the generator operated when competition applied to it.
- As a minimum the premium cost the market paid for power between the actual (market power driven) cost and cost if the market had followed consistent pricing practices without exercising market power, needs to be refunded to the market (including recovery of the capital investment). This could be achieved by AEMO being instructed to change the prices in the market for the period to the non-market power driven prices and there are mechanisms in the NEM already which allow the changing of payments after the event, although such changes are usually minor (eg where AEMO has made a mistake). Implicitly this means that AER has to announce that it is investigating the price and that the market prices might be changed, to carry out its review quickly and then advise the new prices that are to apply. AEMO will then have to reset the amounts payable to each participant for the periods under review. In other jurisdictions (eg by Ofgem with its approach proposed in 2000, or by ERCOT) restitution is not made directly to those consumers who suffered.
- It is probable that the AER would err on the side of conservatism in its assessment and so there may still be a premium built into the outworkings of the AER. Because of this a fine needs to be imposed that would deter a generator from even attempting to exercise market power. If the AER determines that it has to adjust the spot prices because of exercise of market power, then the generators found guilty need to be fined as well losing much of the benefit of exercising market power. The current level of fine of $1m is far too low for an extended and/or repeated use of market power and should therefore be increased if the period of the exercise of market power is of more than one half hour period. Alternatively the current $1m fine could apply to each half hour period the AER identifies the generator has exercised market power.

Pros

- An ex post approach is probably a more palatable reform than structural or ex ante approaches because an ex post approach is already implicit in the Rules in that the AER is required to assess any price excursion >$5000/MWh and to assess whether there has not been “good faith” bidding or rebidding,
- An ex post approach would expand on what is already in place as there is implicitly already an ex post process in the rules. An ex ante approach requires significantly more change to the rules.
- Ex post assessments are used in other jurisdictions so there is an ability to develop NEM specific rules based on approaches already in use.

Cons

- There is difficulty in returning to the market the price premium paid by the market initially as a result of the exercise of market power, because a NEM principle is that prices once declared set the payments made within the market
- The time needed to assess the activities of generators is considerable and this causes both costs for the evaluation and delays in resolving the issue. This might cause changes to any AER assessment

- As the outcome of such investigation could result in significant payments (return of funds and dines) the offending generator should have a right of appeal and this could result in changes to the AER assessment and cause further delays in finalising the issue.
- If there is to be restitution non offending generators would have to return the premium they garnered from the market as well. This would create financial hardship as the delay in the findings could be quite long.

2. ex ante option

- An ex ante control approach would apply constraints as the way a generator is permitted to bid
- This approach is used in the north east of the US, although this area of the US uses a capacity market approach of generator payment. Because there are payments for capacity, it is expected that the prices for energy provided might more closely reflect short run marginal cost, making assessments of the exercise of market power easier
- An ex ante approach can be quite complex but the basic concept is that it constrains generators to always providing prices which fit within the usual envelope of each generator’s pricing approach, and therefore effectively prevents a generator of pricing at the market price cap when it has market power.
- An ex ante approach can be applied to all generators able to bid in a region, or it could be applied just to generators which might be seen to be able to exercise market power at some time.
- In setting the permitted pricing envelope for a generator, the regulator would have to assess a multiple number of issues such as the generator’s ability to quickly respond (eg because of its ramp rates), when and how long a generator should be permitted to exercise market power, whether there is credible competition, what should be the envelope of pricing permitted for each generator (eg a base load generator might have a lower price constraint than a peaking generator), when should the constraint be applied (eg when demand exceeds a certain value), etc. A review of the New York regional rules shows that the envelope of constraints is quite complex.
- In its simplest form the AER could focus purely on the dominant generator in each region and identify at what regional demand it could exercise market power. The AER could then set a maximum price at which that generator (ie a designated generator or generators) can offer its capacity at (eg the level set for the administered price cap – currently $300/MWh), the number of price periods before this administered price will be imposed on the generator, a restriction on how much the generator can reduce its output once the administered price is imposed, etc
- Under this simple approach of ensuring the designated generator did not withhold capacity, AEMO would “call” the designated generator to dispatch all of its available capacity at a price less than the administered price cap (APC). Other generators would be dispatched in accordance with their bids and offers, so that if the spot price exceeded the APC applied to the designated generator, then all generators (including the designated generator) would receive the spot price, effectively retaining the integrity of the market structure.

Pros

- The practice has been used in other jurisdictions.
- At its most simple the imposition of pricing constraint can be very limited – to just 1 or 2 generators in a region, and only when the demand is forecast to exceed a predetermined level
- The approach prevents the exercise of market power and allows the market to clear in the usual way and therefore there is no need to adjust the payments between market participants at a later stage.
- It effectively forces the dominant generator to operate in a way that approaches the implicit concept of the market in that lowest cost generators are dispatched ahead of higher cost generators
- It does not require an ability to allocate the return of excess revenue to those who suffered because of the exercise of market power

Cons

- Imposing a price on generation might be considered to be anti-competitive and relatively inflexible as it does not necessarily allow for any extenuating circumstances
- Setting the operating envelope would be subject to challenge by the generator
- If the spot price exceeds the administered price cap for the dominant generator, does the dominant generator receive the dispatch price or the administered price for that generator? Depending on the answer, there is a risk that the dominant generator will still operate economic withdrawal of capacity
- What happens if the demand is higher than what can be provided by the dominant generator when it is operating at full capacity?
- How can we be sure that the dominant generator is operating at its full capacity?
- Analysis will be needed to assess whether a designated generator did in fact dispatch all of its available capacity when called by AEMO or whether it still withheld some capacity so as to drive the spot price up
- An ex ante approach requires a significant change to the market concepts and rules as the rules are currently based on a ex post review

Appendix 2

Analysis of the NEM operation

The data shows that the impact of a very few price spikes has a massive impact on the average spot prices. In particular 78 high price events in SA in 2008 (ie for 0.5% of the time) caused over half (57.1%) of the average volume weighted price. This was replicated in 2009.

The time weighted price reflects the spot price to a user with a flat load.

The volume weighted price reflects the spot price to a user with a load that matches the regional average.

If the flat loads are excised from the average demand, a typical residential user would exhibit a load which has a more peaky demand than the average state demand shape and so would pay a higher price than the volume weighted average.

All data in the following tables is derived from AEMO data and calculated by MEU.

2009 data	**Qld**	**NSW**	**Vic**	**SA**	**Tas**	**NEM (excl Tas and Snowy)**
% of average annual volume weighted price caused by >$300 price spikes	24.2%	42.5%	34.4%	66.5%	31.9%	39.9%
% of average annual volume weighted price caused by >$1000 price spikes	23.5%	41.0%	34.1%	65.7%	27.9%	38.9%
Av annual time weighted regional price $/MWh	34.13	43.92	36.48	60.47	50.20	43.75
Av annual volume weighted regional price $/MWh	37.42	51.63	43.68	89.84	53.82	48.34
# price spikes >$300/MWh in 2009	42	89	37	129	103	297
# price spikes >$1000/MWh in 2009	33	56	27	78	64	196

2008 data	Qld	NSW	Vic	SA	Tas	NEM (excl Tas and Snowy)
% of average annual volume weighted price caused by >$300 price spikes	22.9%	14.1%	10.3%	57.1%	0.7%	24.3%
Av annual time weighted regional price $/MWh	43.87	39.12	40.24	66.37	49.73	47.41
Av annual volume weighted regional price $/MWh	48.81	42.13	43.45	92.70	50.67	47.70
# price spikes >$300/MWh in 2008	62	23	21	78	4	184

2007 data	Qld	NSW	Vic	SA	Tas	NEM (excl Tas and Snowy)
% of average annual volume weighted price caused by >$300 price spikes	25.9%	27.3%	19.7%	12.1%	4.5%	24.1%
Av annual time weighted regional price $/MWh	66.84	67.07	63.40	57.49	56.85	63.70
Av annual volume weighted regional price $/MWh	72.73	76.01	69.58	64.89	58.97	72.68
# price spikes >$300/MWh in 2007	160	213	132	78	36	583

2006 data	Qld	NSW	Vic	SA	NEM (excl Tas and Snowy)
% of average annual volume weighted price caused by >$300 price spikes	18.2%	20.6%	20.9%	19.4%	20.1%
Av annual time weighted regional price $/MWh	25.97	31.01	34.13	38.68	31.02
Av annual volume weighted regional price $/MWh	28.23	34.81	37.65	44.68	34.49
# price spikes >$300/MWh in 2006	27	32	47	62	168

2005 data	Qld	NSW	Vic	SA	NEM (excl Tas and Snowy)
% of average annual volume weighted price caused by >$300 price spikes	19.6%	36.6%	7.6%	10.1%	24.6%
Av annual time weighted regional price $/MWh	25.17	35.83	26.29	33.60	30.22
Av annual volume weighted regional price $/MWh	27.12	40.84	27.83	36.76	33.44
# price spikes >$300/MWh in 2005	26	67	24	35	152

Appendix 3

FERC six market behaviour rules

1. **Unit Operation**: We proposed that sellers be required to operate and schedule generating facilities, undertake maintenance, declare outages, and commit or otherwise bid supply in a manner that complies with the rules and regulations of the applicable power market;
2. **Market Manipulation**: We proposed to prohibit all forms of market manipulation;
3. **Communications**: We proposed to require that sellers provide complete, accurate and factual information and not submit false or misleading information, or omit material information, in any communication with the Commission, market monitors, regional transmission organizations (RTOs), independent system operators (ISOs), or similar entities;
4. **Reporting**: We proposed to apply this same standard with respect to reports made by sellers to publishers of electricity or natural gas price indices;
5. **Record Retention**: We proposed to require sellers to retain for a period of three years all data and information necessary for the reconstruction of the prices they charge, and the prices they report for use in published price indices;
6. **Related Tariffs**: Finally, we proposed to clarify that sellers would not be permitted to violate or collude with another party in actions that violate seller’s code of conduct or Order No. 889 standards of conduct.

Appendix 4(a)

Generator Market Power in the Electricity Supply Industry

A review of the mitigation of generator market power in the British, Albertan, US North Eastern, and Texan electricity markets,

by Alex Henney
EEE Ltd
October 2008

Appendix 4(b)

Generator Market Power in the Electricity Supply Industry

A review of the mitigation of generator market power in the British, Albertan, US North Eastern, and Texan electricity markets,

by Alex Henney
EEE Ltd

Update: July 2010

THE MARKET ABUSE LICENCE CONDITION ENACTED IN BRITAIN

Generator Market Power in the Electricity Supply Industry

A review of the mitigation of generator market power in the British, Albertan, US North Eastern, and Texan electricity markets

By

Alex Henney

EEE Ltd

October 2008

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For M.L.

1. EXECUTIVE SUMMARY

1.1 Background

Generators in the Australian National Electricity Market have a relatively low hurdle to comply with when assessing whether or not they have exercised market power. The key reference point is whether the generators have made an offer, bid or rebid in “good faith”. There is no apparent constraint as to the reasons justifying making an offer, bid or rebid in good faith, and this could easily include making such purely to increase profitability. The aim of this report is to identify whether the electricity rules in Britain and other jurisdictions apply greater, lesser or similar levels of control by regulators on the exercise of market power by generators. Market power is defined as *the ability of either an individual supplier or group of suppliers acting in a coordinated manner (which may be explicit or tacit) to profitably maintain prices above competitive levels for a significant period of time.*

In the European Union Article 82 of the European Community Treaty is the key element of European antitrust law on abuse of market power. It applies to situations in which a single firm unilaterally or multiple firms collectively may be considered to have a dominant position and that firm (or collectively those firms) abuse their dominance by either raising prices directly or taking actions to harm competitors and solidify their market position in a manner that ultimately raises prices above the level that would prevail absent these actions. The basis of US competition law is included in the Federal Trade Commission Act, which prohibits “unfair method of competition”, now taken to mean that it is unfair to deprive consumers [and other parties such as competitors] of the benefits of an open, competitive marketplace.

The mitigation of market power in electricity markets is an important issue because, for several reasons, electricity markets are particularly susceptible to the exercise of market power:-

- Short-term demand for electricity is relatively price-insensitive, while the marginal cost of incremental supply often increases substantially when the market is tight and demand is close to available capacity. Consequently withholding small amounts of generation can increase prices significantly

- System reliability requires that supply and demand has to be balanced continuously and at every location in the transmission network, as electricity cannot be stored. Consequently some generators can exercise market power over relatively short time periods (*e.g.*, a few hours on a given day)

- Transmission constraints can give generators in import constrained areas, market power.

- The increasing trend to vertical integration 1) reduces the liquidity of the forward contract market, and 2) can give vertically integrated companies the power to "margin squeeze" other generators or retailers. These factors can limit new entry.

- Sellers and buyers interact repeatedly in wholesale electricity markets, which facilitate tacit collusion.

Concerns about market power are particularly acute during high load conditions, or when there are significant transmission or generation outages, because a single firm or a small number of firms may be "*pivotal suppliers*" (i.e. their supply is necessary in order to satisfy the outstanding demand), and even modest amounts of economic or physical withholding may lead to substantial increases in price. The British regulator, Ofgem, maintains that even market participants with low market shares (below normal thresholds for considering dominance) "may have the ability substantially and consistently to influence prices, and therefore to act independently of customers and competitors." It further maintains that "large price increases that are sustained only for a short period or small price increases over a long period of time" may both constitute a breach of competition law.

This paper examines the powers available to identify and mitigate market power in Britain, Alberta, and the US as exemplified by the markets in New York, New England, the PJM and Texas.

1.2 Market power mitigation in Britain

Britain has an energy only bilateral or net market. There are no *ex-ante* mechanisms in place such as price caps to prevent the exercise of market power by generators. Ofgem adopts an *ex-post* approach to mitigating abuses of market power in electricity markets when it claims that "an investigation will focus on the commercial conduct of the relevant undertaking(s) and on the effects on customers of the conduct or agreements entered into by undertakings".

It has powers to investigate and take enforcement action in relation to suspected infringements of United Kingdom and European Community competition laws. Its enforcement powers include the ability:-

- to give directions to bring an infringement to an end. To address structural problems in power markets, Ofgem can require generators to divest some of their assets

- to accept binding commitments to address competition concerns

- to impose financial penalties on undertakings of up to 10% of an undertaking's worldwide turnover in the business year preceding the date of the decision

Ofgem also has the power to propose conditions to generation (and other) licences. In 2000 it attempted to add a "market abuse licence condition" to the licenses of the seven largest generators in England & Wales. Market abuse was defined as an act that (i) prejudices the efficient and economical operation of the transmission system; (ii) limits generation capacity availability in such ways as to materially increase wholesale electricity prices which would have applied both to the physical withholding of capacity in service and the closure or mothballing of capacity that would be economic to operate; and (iii) pursue discriminatory pricing policies by determining wholesale prices that differ unduly between times when market demand and cost conditions are similar. But on challenge to the Competition Commission, which is the regulator of last resort for utilities, Ofgem lost.

The regulatory effort to counter market power can be divided into five phases:-

1. Various reports from 1990-93, which achieved little.

2. Price controls during 1995-96 from which the generators actually increased their profits, and divestment of 6GW by National Power and PowerGen which achieved nothing.

3. Further divestment in 2000, which together with the increase of merchant CCGTs coming on stream, fragmented the industry and reduced prices, and an abortive attempt to introduce a Market Abuse Licence Condition.

4. The introduction of NETA in 2001 which, at considerable cost, achieved nothing.

5. Ofgem then sat back and did nothing until the Business and Enterprise Committee of the House of Commons undertook its own report and prompted Ofgem to investigate the market. It has published an initial report on the retail market, and will be examining the wholesale market.

1.3 Market power mitigation in Alberta

In 1996 competitive restructuring was introduced with a gross energy only Pool and access to transmission. But the industrial structure was not promising; all plant was owned by three companies. Two market power mitigation mechanism are of interest in Alberta, the virtual power plant auctions and the style of the Market Surveillance Administrator:-

- The Electric Utilities Amendment Act 1998 empowered the government to introduce auctions offering long term power purchase agreements (PPAs), which were for the shorter of the regulated accounting life of the plants or until 2020. In 2000 Alberta's generation plants were grouped into

12 PPAs for a total of 6.4GW; the purchasers dispatched the plants; the plant owners received a regulated income from the sale of the PPAs and a levy if needed to make them whole. The auction reduced the HHI of generation from about 3500 in 2001 to about 750 in 2001, and thus contributed to creating a competitive market with falling prices

- The Market Surveillance Administrator (MSA) is responsible for ensuring that "market participants conduct themselves in a manner that supports the fair, efficient and openly competitive operation of the market". The MSA has examined and effected changes to:-

  * the Spinning Reserve Market, which one company was manipulating. A new arrangement was agreed and "Since its signing, more rational market clearing prices that better reflect competitive forces have been observed"

  * the problems with transmission must run contracts. The MSA made a number of recommendations calling on both regulator and the Pool to alter practices especially improving transparency regarding the contracting of TMR contracts and calling them, and that it would monitor the use of non-competitive processes by the Pool

- Currently it is engaged in an investigation into alleged dumping through the interconnector with British Columbia. Although the effect of this is to reduce prices, "excessive" exporting would increase prices in Alberta

- The government is introducing a "Fair, Efficient and Open Competition" Regulation which defines a range of prohibited behaviour, and limits control (whether by ownership or contract) by any one market participant to a maximum of 25% of the capacity on the system

1.4 Market power mitigation in some US power markets

The Federal Energy Regulatory Authority (FERC), which regulates wholesale markets in the US other than in Texas, was scarred by the crisis in California of 2000-01, which led to a far more interventionist approach to market power mitigation than is practiced elsewhere.

The Federal Power Act, under which FERC functions, is a regulatory statute, not an antitrust law, and was not ideally suited for restructuring electricity markets. Its primary regulatory goal is the attainment of *"just and reasonable prices"*, not the promotion of competition. The Act now prohibits the use or employment of "manipulative or deceptive devices or contrivances in connection with the purchase or sale of natural gas, electric energy, or transportation or transmission services subject to the jurisdiction of FERC". Market power is abused in electricity markets when it is exercised beyond allowable levels or benchmarks, resulting in prices that are not considered *just and reasonable.* Courts have determined that an unjust and unreasonable rate is one that falls outside the zone of reasonableness, where that zone excludes rate levels that are "less than compensatory" to producers or "excessive" to consumers. That is, on the one hand, rates should be high enough to give producers a reasonable opportunity to recover their costs, including a risk-adjusted return on capital, but sufficiently low to avoid consumer harm. FERC does not have the power to impose structural remedies (e.g. divestiture) to address the unilateral or multilateral exercise of market power. As a consequence, there is widespread recognition, particularly in the US, that some level of *ex ante* mitigation of market power is advisable.

"FERC finds that wholesale electric markets are not yet structurally competitive in all respects. Specifically, FERC identifies the lack of price-responsive demand and generation concentration in transmission-constrained load pockets as two structural flaws in these markets, which create the potential for participants to exercise market power, defined as the ability to raise price above the competitive level". Furthermore FERC staff are clear that:-

> "It is difficult to separate scarcity from market power…during periods when electricity becomes more scarce, the price naturally increases".

FERC's approach is to aim to mitigate the exercise of market power in the day-ahead and real time energy markets so that prices approximate system marginal cost. The income from their energy markets will not recover income necessary to remunerate generators' investment, so in addition there is income from a capacity market and ancillary services which together remunerate investment in generation.

FERC believes that "the ISO/RTO must address economic withholding in the spot markets by implementing market rules that act to limit spot market bids, before the settlement price takes effect. This is preferable to letting spot markets work initially without restraint, then trying to detect bad behaviour after the fact, and later making amends by trying to determine what the correct market prices should have been.

The three North Eastern markets examined in the paper in New York, New England, and the PJM have the common features that they are all broadly the Standard Market Design, with a day ahead energy spot market and a real time energy spot market; are based on locational marginal pricing (LMP); have a capacity market of some sort; and each of the markets has an Independent Market Monitor who annually examines the performance of the market, including the exercise of market power, in detail (the report by the PJM Monitor is 495 pages). In assessing the overall structural situation of the potential for market power, they all use:-

- HHI as a measure of concentration
- The residual supply index (RSI) is a measure of the extent to which a generation owner is a pivotal supplier. This is a key metric in triggering conduct mitigation in New England and PJM

In assessing ex-post the overall level of the exercise of market power they all use the price-cost markup index.

Both the New York and the New England markets use a multi step approach to market power mitigation checking first the *conduct* of a generator in making offers, and second analyzing the price *impact* of the offer. The focus of the PJM mitigation effort is on load pockets, where there is automatic mitigation of bids from generating units dispatched for congestion relief unless a structural screen (the three jointly pivotal supplier test) is passed on a day-ahead and real-time basis.

New England has implemented a new form of capacity market called the "Forward Capacity Market", which also mitigates market power. If the system is under stress and the spot price rises above the strike price then the generator has to pay the difference to ISO-NE. This payment has two consequences. First, it gives the generator a clear incentive to be generating when the price is high in order to make the money to offset the payment. And second, to the extent that it is contracted, the payment eliminates the incentive for the generator to price high because the generator has to pay the difference between price offer and strike price to ISO-NE. Although ISO-NE has held the first auction, the products do not come into effect until June 2010 so their effectiveness in mitigating market power cannot be judged.

The ERCOT market in Texas is under the jurisdiction of the Public Utilities Commission of Texas (PUCT). It is currently a zonal market (but will change to an LMP design in 2009); it is – and will remain – an energy only market. With two dominant generators, the PUCT has been concerned both about local market power in the constrained areas around Houston and Dallas-Fort Worth, and about general market power. It has an ongoing court case on the issue against TXU.

1.5 Experiences with mitigating market power

The case studies show that there are two broad approaches to mitigating market power:-

- *Ex ante* mitigation with restrictions on the behaviour of firms, such as price caps, bidding restrictions, or mandated prices that reflect anticipated costs which do not rely on extensive fact finding, analysis and prosecution. The approach is exemplified by the US North East markets, which are characterized (as is the Australian National Electricity Market) by a formal and transparent compulsory stacking energy market (i.e. a gross pool), which allows easy identification of who is doing what

- *Ex post* enforcement, which focuses on identifying after-the-fact instances of anti-competitive conduct (e.g. evidence of collusion, significant output withholding or other inefficient behaviour) and punishing the behaviour (*e.g.*, fines, damages payments, etc.). This approach is favoured by Britain (and all other European countries) and Alberta

The case for *ex ante* mitigation is that it is comparatively quick and formulaic, is transparent, and reduces regulatory risk because it avoids the often slow, potentially costly, uncertain, and burdensome investigations associated with *ex post* enforcement regimes. The case against *ex ante* is it risks being too prescriptive, overly broad, and having unintended consequences, notably the implementation of mitigation actions when market power abuse does not exist. By contrast, *ex post* can be less formulaic and more specifically tailored to those instances in which a market participant is demonstrated to have engaged in anticompetitive or otherwise inefficient behavior.

The implementation of automatic *ex ante* mitigation in US organized electricity markets coupled with *ex post* monitoring and enforcement capability differs significantly from the almost sole reliance on *ex post* mitigation regimes used in most other markets, including the electricity markets in Britain and Alberta. The combination of *ex ante* and *ex post* mitigation is a significantly more stringent enforcement regime than the approaches adopted in Alberta and Britain.

Another fundamental difference between the markets is that three are energy only markets (Britain, Alberta, Texas) and three have associated capacity markets. A necessary requirement of an energy only market is that generators have to exercise market power to increase prices above system marginal cost in order to recover their investment. This raises the very difficult question of how to judge what is reasonable. In contrast the three US North East markets have associated capacity markets which provide a supplementary income that allows the energy markets to be mitigated to (near) system marginal price.

1.6 Conclusions

It is clear that the risk of exercise of generator market power has been identified and addressed in considerable detail in these jurisdictions. Regulators and legislators have recognised that the electricity market is particularly susceptible to the exercise of generator market power. FERC has taken the view that it is not possible in an energy only market to differentiate between the scarcity pricing needed to remunerate capacity in an energy only market, and the exercise of market power. It has consequently supported an ex-ante approach that mitigates offers to the energy market to more or less system marginal costs and complements the revenue from the energy markets with a capacity market (which also assures generation adequacy). This approach is adopted in the three North Eastern markets of New York, New England, and PJM. The authorities responsible for the other three markets – Britain, Alberta, and Texas, which are all energy only markets – have adopted an ex-post approach. The British authorities have tried restructuring the market (which achieved nothing) and divestment as a remedy to market power, which worked for a while until the authorities allowed the electric industry to consolidate and vertically integrate; now the problem may have emerged again. Alberta has resolved a couple of issues by the regulator getting changes made to market arrangements. The Texas regulator is trying to discourage the exercise of market power by imposing a fine representing triple the amount that market revenues increased resulting from the abuse of market power.

Without a doubt the US approaches – whether in the ex-ante mitigation in the FERC markets or the attempt by the Texas regulator to impose a very large fine for market power abuse – are much tougher than the approaches adopted in Alberta and Britain. And all of the jurisdictions have much more forceful means of market power mitigation than the NEM.

2. INTRODUCTION

This paper responds to a request by electricity consumers (as represented by the Major Energy Users) in Australia's National Electricity Market (NEM) to assess whether other jurisdictions have more or less stringent rules limiting electricity generators from exercising market power. Reference has been made to where generators in Australia (notably Macquarie Generation in New South Wales during mid 2007 and AGL/Torrens Island Power Station in South Australia in early 2008) appeared capable of setting the electricity spot market price at very high levels for significant periods of time. The National Electricity Rules in Australia's NEM state in Section 3 that

> **3.8.22A Variation of offer, bid or rebid**
>
> (a) *Scheduled Generators* and *Market Participants* must make *dispatch offers, dispatch bids* and *rebids* in good faith.
>
> (b) In clause 3.8.22A(a) a *dispatch offer*, *dispatch bid* or *rebid* is taken to be made in good faith if, at the time of making such an offer, bid or *rebid*, a *Scheduled Generator* or *Market Participant* has a genuine intention to honour that offer, bid or *rebid*, if the material conditions and circumstances upon which the offer, bid or *rebid* were based remain unchanged until the relevant *dispatch interval*.
>
> (c) A *Scheduled Generator* or *Market Participant* may be taken to have contravened clause 3.8.22A(a) notwithstanding that, after all the evidence has been considered, the intention of the *Scheduled Generator* or *Market Participant* is ascertainable only by inference from the conduct of the *Scheduled Generator* or *Market Participant*, or of any other person, or from relevant circumstances.

This is the extent of the controls on market power that a generator may have in setting the spot price in the NEM under the National Electricity Rules. Note that the controls appear to be limited to a requirement to act in "good faith", but there is no attempt to identify as what is intended by the term "good faith" other than its common meaning of "honesty of intention"[1].

There are general powers available to the Australian Consumer and Competition Commission (ACCC) under the Australian Trade Practices Act to limit the exercise of market power. There is, however, no attempt made in this paper to assess whether the Trade Practices Act provides greater protection to electricity consumers than the provisions in the National Electricity Rules.

The paper is organized in the following sections

- Section 3 examines the concept of market power, and the general legal provisions in the European Union and the US for dealing with it

[1] Encarta Dictionary: English (UK)

- Section 4 looks at the particular problem of market power in electricity markets
- Section 5 describes market power mitigation in Britain
- Section 6 describes market power mitigation in Alberta
- Section 6 describes market power mitigation in some US power markets, starting by looking at the crisis of market power in California which drove FERC's approach to mitigating market power. The section then looks at the market monitoring and market power mitigation arrangements in the energy markets of New York, New England and PJM which FERC regulates, and concludes by examining market power mitigation in the ERCOT market in Texas
- Section 8 looks at experiences with mitigating market power
- Section 9 draws major conclusions

There are three annexes:-

- The way of the market in England & Wales then Britain and Ofgem's response to market power
- **Alberta - Draft of Fair, Efficient and Open Competition Regulation**
- PUCT letter re Notice of Violation by TXU Corp.

3. THE GENERAL CONCEPT OF MARKET POWER AND ANTITRUST RESPONSES

Market power is defined as *the ability of either an individual supplier or group of suppliers acting in a coordinated manner (which may be explicit or tacit) to profitably maintain prices above competitive levels for a significant period of time*[2].

The mere *possession* of market power exercised by suppliers is not uncommon or illegal in itself. Indeed it is common in many markets for sellers to have a modest amount of market power (*i.e.*, some ability to raise price). But the exercise of market power results in a product price that exceeds underlying marginal production costs and less output is produced than in a "perfectly competitive" market - typified by the apocryphal grain market consisting of many buyers and many sellers, none of whom is large enough to set the price and all of whom are consequently price takers - where price equals marginal cost. Market power exercised by suppliers leads 1) to a deadweight loss measured as the difference between what buyers would be willing to pay for the forsaken output and its associated production costs, and 2) can result in large wealth transfers from buyers to sellers. This is an especially important consideration in electricity markets because it is a necessity purchased by every household and business and is vital to health, safety, and economic viability.

Professor Alfred Kahn[3], in *The Economics of Regulation*, refers to "effective competition" as the ultimate goal of the policymaker, pointing out that perfect competition is not a practical objective standard for a regulator to pursue:

> "The main reasons why pure competition is in fact not ideal are familiar: (1) economies of scale in production and distribution will typically require that sellers (and buyers) be larger in size and fewer in number than would be consistent with an utter absence of monopoly (or monopsony) power; (2) consumers want variety in service quality and characteristics, which means that there cannot always be a large number of sellers of the same (standardized or undifferentiated) product; (3) effective innovation may, similarly, require firms too large and, hence, too few in number for monopoly power to be completely absent… (4) competitive structure may, in the presence of serious imperfections of competition, be too pure in other respects—entry too free and rivalry too intense—for optimum performance. All of these considerations make the determination of what kinds of policy will produce the most effective competition difficult enough in unregulated industry generally; they make it even more

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[2] Market power can be exercised in other ways in *the short term,* such as predatory pricing or devising barriers to entry. But such measures nearly always have *the longer term* objective of eventually leading to higher prices. It can also be exercised by buyers.

[3] Alfred Kahn is Robert Julius Thorne Professor Emeritus of Policy Economics at Cornell University. He was once chairman of the New York Public Service Commission, and as chairman of the Federal Aviation Authority he played a major role in the deregulation of US airlines in the 1970s.

> difficult in the public utility arena, which has been subject to more direct regulation precisely because of the presence there of unusually strong circumstances making unrestrained competition both infeasible and undesirable".

This has led to the notion of "workable" competition as a more realistic goal than the theoretical concept of "perfect competition." Under workable competition, price may exceed marginal cost to some extent and firms may engage in limited exercises of market power. Based on this concept of workable competition, the abuse of market power means exercising market power beyond a level determined by public authorities to be the limit of reasonable pricing and proper market operations.

Central to the consideration of market power is the definition of the product being considered, and also the geographical area of the market. Although its purpose is to define product and geographic markets in merger reviews, the approach used in the US Department of Justice and Federal Trade Commission's "Horizontal Merger Guidelines" (*Guidelines*)[4] is accepted in various jurisdictions (including the European Union, see Directorate General Competition discussion paper on the application of Article 82 of the Treaty to exclusionary abuses, Brussels, December 2005[5]) as a useful conceptual framework for defining markets for more general antitrust and regulatory purposes. Under this approach, a product market is defined by taking an individual product and assessing whether it would be profitable theoretically for all producers of that product within a specified geographic area to *collectively* institute a "*small, but significant, and nontransitory increase in price*" ("SSNIP"), which is typically 5-10%. If, in response to the price increase, consumers switch to other alternatives and the hypothetical price increase would be unprofitable, then producers of that product alone would have failed the SSNIP test, and are not considered to possess significant market power. The candidate product market would then be expanded to include "the next-best substitute", and the SSNIP test would be applied to all producers of the original product and the substitute product. This process continues until the candidate product market passes the SSNIP test.

3.1 General competition law in the European Union

In the European Union (EU), the Directorate-General for Competition of the European Commission is the antitrust competition authority. Article 82 of the European Community Treaty is the key element of European antitrust law on abuse of market power. It applies to situations in which a single firm unilaterally or multiple firms collectively may be considered to have a dominant position and that firm

[4] Section 1.0., Horizontal Merger Guidelines, United States Department of Justice and Federal Trade Commission (1997).
[5] http://ec.europa.eu/comm/competition/antitrust/art82/discpaper2005.pdf.

(or collectively those firms) abuse their dominance by either raising prices directly or taking actions to harm competitors and solidify their market position in a manner that ultimately raises prices above the level that would prevail absent these actions. The Article permits authorities to intervene solely on the basis of excessive pricing.

In "The Assessment of Market Power: Understanding Competition Law", the British Office of Fair Trading (OFT) [6] points out that Article 82 prohibits conduct by one or more undertakings which amounts to the abuse of a dominant position. The European Court of Justice (ECJ) has defined a dominant market position as:-

> 'a position of economic strength enjoyed by an undertaking which enables it to prevent effective competition being maintained on the relevant market by affording it the power to behave to an appreciable extent independently of its competitors, customers and ultimately of consumers.'

OFT observed that this effectively implies market power, but without using those words:-

> "The concept of market power is not part of the statutory framework of the EC Treaty or the Act, but it is a useful concept in assessing potentially anti-competitive agreements or conduct…Market power can be thought of as the ability profitably to sustain prices above competitive levels or restrict output or quality below competitive levels".

The ECJ has held that it may be a violation of Article 82 for an undertaking in a dominant position to charge a price which is excessive in relation to the economic value of the service provided or the good supplied. According to the ECJ, excessive pricing practices can be identified using different methodologies: (i) comparing prices with cost measures for the dominant firm; (ii) comparing prices with those of firms offering substitute products; (iii) comparing prices with firms operating in different geographic areas but offering similar products.

There are no market share thresholds for defining dominance under Article 82 or the Chapter II prohibition, but the ECJ has stated that dominance can be presumed in the absence of evidence to the contrary if an undertaking has a market share persistently above 50%[7]. The OFT considers that it is unlikely that an undertaking will be individually dominant if its share of the relevant market is below 40 per cent, although dominance could be established below that figure if other relevant factors (such

[6] Assessment of Market Power: Understanding Competition Law, OFT, 2004, http://www.oft.gov.uk/shared_oft/business_leaflets/ca98_guidelines/oft415.pdf.
[7] Case C62/86 AKZO Chemie BV v Commission [1991] ECR I-3359.

as the weak position of competitors in that market and high entry barriers) provided strong evidence of dominance.

Article 82 and the Chapter II prohibition prohibit conduct on the part of ‘one or more’ undertakings that amounts to the abuse of a dominant position. A dominant position may be held collectively (“a collective dominant position”) when two or more legally independent undertakings are linked in such a way that they adopt a common policy on the market. The ECJ confirmed the principle of collective dominance in the ‘Italian Flat Glass’ case:-

> “There is nothing, in principle, to prevent two or more independent economic entities from being, on a specific market, united by such economic links that, by virtue of that fact, together they hold a dominant position vis-à-vis the other operators on the same market”[8].

The links may be structural or they may be such that the undertakings adopt a common policy on the market. For example, the nature of the market may mean that undertakings might adopt the same pricing policy on the market without ever explicitly agreeing on price[9], which is tacit coordination. Tacit coordination requires that undertakings are able to align their behaviour in the market. It also requires that:-

- each undertaking is able to monitor the compliance of the other undertakings with the common policy (i.e. transparency)
- the undertakings have incentives to maintain coordinated behaviour over time, so that coordination is sustainable (e.g. because deviations from the common policy are easy to detect and punish)
- the foreseeable reactions of current and future competitors, as well as of customers, would not jeopardise the results expected from the common policy (e.g. new entrants, ‘fringe’ undertakings or powerful buyers could not successfully challenge the common policy)[10]

In Assessment of Conduct[11] the OFT provides guidance on how certain conduct by dominant undertakings (whether individually or collectively dominant) that might be prohibited under Article 82 and/or the Chapter II prohibition of the Act will be assessed by the OFT. The charging of excessive selling prices by a dominant undertaking may be an infringement of Article 82 and/or the Chapter II prohibition. In the United Brands case the ECJ held that:

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[8] Case T-68/89 etc Società Italiano Vetro SpA v Commission [1992] II ECR 1403.
[9] Case C396/96 *Compagnie Maritime Belge Transports v Commission* [2000] ECR I-1365 at paragraph 45.
[10] See the judgment in Case T-342/99 Airtours plc v Commission [2002] ECR II-2585.
[11] Assessment of Conduct, Draft competition law guideline for consultation, April 2004, http://www.oft.gov.uk/shared_oft/business_leaflets/competition_law/oft414a.pdf.

> 'charging a price which is excessive because it has no reasonable relation to the economic value of the product supplied… would be… an abuse'[12].

The ECJ went on to declare that a detailed analysis of costs would be required before any judgement of excessive prices could be reached and added that the question to be asked was:

> '... whether the difference between the costs actually incurred and the price actually charged is excessive, and, if the answer to this question is in the affirmative, whether a price has been imposed which is either unfair in itself or when compared to other competing products.'

In order to address whether an undertaking's prices are higher than would be expected in a competitive market, the OFT proposes that the following benchmarks might be considered:-

- "Comparisons with prices of the same products in other markets…provided that these markets are subject to similar cost conditions as the market in question
- Comparisons with underlying costs where it is possible to derive an economically meaningful measure of an undertaking's own costs…
- Comparison with prices in another time period. Evidence that prices were substantially higher than those of a period when competition was more effective might provide evidence of excessive pricing, provided that there were no other good explanations for the price rise (e.g. a substantial increase in cost)"

But the OFT does warn that "Prices and profits of a dominant undertaking which, at first sight, might appear to be excessive will not always amount to an abuse". It gives three examples:-

- "High prices will often occur for short periods within competitive markets. For example, an increase in demand that could not be met by current capacity or a supply shock that reduced production capacity would lead to higher prices. Where high prices are temporary and/or likely to encourage substantial new investment or new entry, they are unlikely to cause concern"
- An undertaking might be able to sustain supra-normal profits for a period if it was more efficient than its competitors…"
- "Prices and profits may be high in markets where there is innovation. Successful innovation may allow a firm to earn profits significantly higher than those of its competitors…"

3.2 US Antitrust Law

The OECD Country study "United States – The Role of Competition Policy in Regulatory Reform" (1998)[13] observes that "In the last 20 years the two US competition policy agencies, the Antitrust

[12] Case 27/76 United Bonds v Commission [1978] ECR 207, [1978] 1 CMLR 429 at paragraph 250 (United Bonds).

Division of the Department of Justice and the Federal Trade Commission, as well as the courts, which are the ultimate authorities, have embraced a basically economic conception of competition policy". The entire corpus of US competition law is included in the Federal Trade Commission Act, which prohibits "unfair method of competition", which is now taken to mean "unfair to consumers", i.e. that it is unfair to deprive consumers [and other parties such as competitors] of the benefits of an open, competitive marketplace.

US antitrust law – the Sherman Act - does not use the term "dominance" or "abuse of dominance" but "monopoly" and "attempt to monopolize." Absent collusion, firms are allowed to enjoy the benefits of market power under US antitrust law. Exploitative pricing behavior by an entity possessing market power does not violate US antitrust law if the "monopolist" has legitimately gained its market position through superior skill and efficiency[14]. Unlike in Europe, antitrust laws do not protect consumers against high prices due to unilateral output withholding.

General competition laws usually address the problems of monopoly power in three formal settings, agreements, mergers or concentrations, and actions by a single firm, which is termed "monopolization". Abuse of monopolizations is concerned principally with the conduct and circumstances of individual firms. Laws against monopolization are typically aimed at exclusionary tactics by which firms might try to obtain or protect monopoly positions. Laws against abuse of dominance address the same issues, and may also try to address the actual exercise of market power. For example under some [what] abuse of charging unreasonably high prices can be a violation of the law.

US energy industry regulators do not have the authority to impose structural remedies (*e.g.*, divestiture) to address unilateral or multilateral market power, and US antitrust authorities rarely

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[13] http://www.oecd.org/dataoecd/3/24/2497266.pdf.

[14] United States Court of Appeals for the Second Circuit, (1980) states:

> "Setting a high price may be a use of monopoly power, but it is not in itself anticompetitive …Judicial oversight of pricing policies would place the courts in a role akin to that of a public regulatory commission"

Likewise United States Supreme Court, (2004) United States Supreme Court (2004). *Verizon Communications, Inc v Law Offices of Curtis V Trinko, LLP* 157 L Ed 2d 823, 836, states:

> "The mere possession of monopoly power, and the concomitant charging of monopoly prices, is not only not unlawful; it is an important element of the free-market system. The opportunity to charge monopoly prices—at least for a short period—is what attracts "business acumen" in the first place; it induces risk taking that produces innovation and economic growth."

succeed in imposing structural remedies (outside of merger cases). As a consequence, there is widespread recognition, particularly in the US, that some level of *ex ante* mitigation of market power is advisable. All the US markets considered *ex ante* mitigation processes are prevalent in all U.S. organized electricity markets.

4. THE PARTICULAR PROBLEM OF MARKET POWER IN ELECTRICITY MARKETS

The mitigation of market power in electricity markets is an important issue because for several reasons electricity markets are particularly susceptible to the exercise of market power:-

(i) Short-term demand for electricity is relatively price-insensitive[15], while the marginal cost of incremental supply often increases substantially when the market is tight and demand is close to available capacity. Consequently withholding of small amounts of generation can produce a large impact on energy prices.

(ii) System reliability requires that supply and demand has to be balanced continuously and at every location in the transmission network, and electricity cannot be stored. Consequently, since intertemporal demand substitutability by consumers is limited, intertemporal supply substitutability cannot constrain attempts to exercise market power over relatively short time periods (*e.g.*, a few hours of a given day)

(iii) Transmission constraints limit the flow of electric power across geographic areas, and can give generators in import constrained areas market power.

(iv) Generators face high sunk costs with lumpy, irreversible, and long lived investments. Together with the increasing trend to vertical integration which reduces the liquidity of the forward contract market and thus giving vertically integrated companies the ability to "margin squeeze" either/both competitor generators and retailers, which can limit new entry.

(v) Sellers and buyers interact repeatedly in wholesale electricity markets, which facilitates tacit collusion.

Concerns about market power are particularly acute during high load conditions, or when there are significant transmission or generation outages, because a single firm or a small number of firms may be *"pivotal suppliers"* (i.e. their supply is necessary in order to satisfy the outstanding demand), and even modest amounts of economic or physical withholding may lead to substantial increases in price.

[15] A study by Green and Newbery "Competition in the British electricity spot market", *Journal of Political Economy*, 100(5): 929-53, (1992) concluded that the elasticity of demand was 0.17 in the England and Wales power pool. Patrick and Wolak "Estimating the customer-level demand for electricity under real-time market prices", Working Paper 8213, National Bureau of Economic Research, Cambridge MA (2001), estimates the short run income elasticity of demand for residential electricity using consumers expenditure survey data. *Energy Journal*, 14(4): 111-21, found that the demand elasticity for most consumer classes in England & Wales was below 0.1 (in absolute value). Branch (1992) estimated a demand elasticity of -0.2 for California customers. Bye, *et al.* (2003) Kraft og Makt. En Analyse av Konkurranseforholdene i Kraftmarkedet. Report for the Norwegian Ministry of Labour and Administration, estimated a demand elasticity of -0.23 using data from October 2002 to April 2003 in the Norwegian electricity market.

In its "Competition Act 1998 – Application in the Energy Sector"[16] the British regulator, Ofgem, considers that there are factors unique to the energy sector or not common in most other markets which are relevant to the application of competition law. The relevant factors relating to markets as opposed to network monopolies include:-

- "the extent of market power of incumbent undertakings in parts of the gas and electricity industries, including supply, metering, connections and storage markets
- the low elasticity of supply and demand for electricity and gas, particularly over short periods and in specific locations. In part this results from the limited storability of electricity, and to a lesser extent gas, which limits the substitution opportunities between time periods on either the supply side or the demand side
- the relative complexity of and the mandatory adherence by market participants to the various rules, codes and agreements in the gas and electricity markets. These include codes that aim to keep the gas and electricity networks operating within safe and efficient operational limits, and which govern customer transfers as well as the connection to and the use of electricity and gas systems
- the economic linkages between different parts of gas and electricity supply chains including: horizontal and vertical linkages, between spot and forward markets, and between gas and electricity wholesale markets

It maintains that even market participants with low market shares (below normal thresholds for considering dominance) "may have the ability substantially and consistently to influence prices, and therefore to act independently of customers and competitors." It further maintains that "large price increases that are sustained only for a short period or small price increases over a long period of time" may both constitute a breach of competition law.

Many electricity markets (including the National Electricity Market) are oligopolistic. Businesses in such markets may sometimes be able to raise prices above the competitive level without having recourse to any explicit agreement or concerted practice. Coordination is more likely to emerge in markets where it is relatively simple to reach a common understanding on the terms of coordination. The simpler and more stable the economic environment, the easier it is for undertakings to reach a common understanding. Indeed, they may by able to coordinate their behaviour on the market by observing and reacting to each other's behaviour. In other words, they may be able to adopt a common strategy that allows them to present themselves or act together as a collective entity. Coordination

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[16] Ofgem 2005 http://www.ofgem.gov.uk/Markets/Archive/1505a%20-%20Competition%20Act%201998%20–%20Application%20in%20the%20Energy%20Sector%202701.pdf

may take various forms including directly coordinating on prices in order to keep them above the competitive level; limiting production or the amount of new capacity brought to the market; dividing the market, for instance by geographic area or other customer characteristics, or by allocating contracts in bidding markets. To this end:-

- Businesses must be able to monitor whether or not the others are adhering to the common policy, which requires that the market is transparent
- The implementation of the common policy must be sustainable over time, which presupposes the existence of sufficient deterrent mechanisms to convince all the undertakings concerned that it is in their best interest to adhere to the common policy

The conceptual approach underlying the SSNIP test is useful for identifying appropriate product and geographic markets for electric power that may be susceptible to significant exercises of market power by taking a group of generators located within an import constrained zone, and assessing whether it would be profitable for that group of generators to collectively attempt to impose a "*small, but significant, and nontransitory increase in price*" (*i.e.*, based on the theoretical assumption they could collectively act like a single monopolist).

The European Commission recently consulted the Committee of European Securities Regulators and the European Regulators' Group for Electricity and Gas on whether Directive 2003/6/EC, the Market Abuse Directive, on insider dealing and market manipulation should be extended from securities and financial instruments to physical gas and electric markets. The regulators have just responded that they "are of the view that the Commission should consider developing and evaluating proposals for a basic, tailor-made market abuse framework in the energy sector legislation for all electricity and gas products not covered by MAD. Such legal framework should address the abusive practices observed or potentially applied by market participants on electricity and gas markets"[17].

[17] CESR and ERGEG advice to the European Commission in the context of the Third Energy Package, Respond to Question F20 – Market Abuse, CERS, EG, October 2008. http://www.e-control.at/portal/page/portal/ERGEG_HOME/ERGEG/ABOUT_ERGEG.

5. MARKET POWER MITIGATION IN BRITAIN

Britain is a large market with 26 million electricity customers and an annual consumption of 330TWh. The wholesale power market started operating in England & Wales in April 1989/90 and extended to include Scotland in 2005. The basis of the market was the Pool of England & Wales, which was an energy only gross pool.

5.1 Ofgem's powers

The Gas and Electricity Markets Authority (GEMA) is the energy sector regulator and the competition authority. The Office of Gas and Electricity Markets (Ofgem) is its executive arm and is often referred to as the regulator, a convention which is followed in this paper. Ofgem has concurrent powers with the Office of Fair Trading under the Competition Act 1998 to investigate and take enforcement action in relation to suspected infringements of United Kingdom and European Community competition laws. The Competition Act (which mirrors the provisions of European competition law) prohibits agreements between companies (*i.e.*, collusion) which have the object or effect of preventing, restricting, or distorting competition. The Chapter II prohibition contained in section 18(1) of the Competition Act 1998 prohibits conduct by one or more undertakings which amount to the abuse of a dominant position in a market in the UK. The Competition Act 1998 confers on the Authority and other sectoral regulators concurrent powers to apply and enforce Articles 81 and 82 of the European Commission Treaty. The powers include the ability:-

- to investigate suspected infringements
- to impose interim measures during the investigation
- to give directions to bring an infringement to an end
- to apply Article 81(3) to agreements which infringe Article 81(1) and section 9 to agreements which infringe the Chapter I prohibition
- to accept binding commitments to address competition concerns, where appropriate
- to impose financial penalties on undertakings of up to 10% of an undertaking's worldwide turnover in the business year preceding the date of the decision

The Enterprise Act 2002 strengthens Ofgem's ability to make exploratory investigations as a basis for making a reference to the Competition Commission for the investigation of particular markets. The Competition Commission is the leading general Competition Authority and also for utilities the regulator of last resort.

In "Competition Act 1998 – Application in the Energy Sector" Ofgem explains its powers and provides guidelines on how it would apply its powers if a case were to be brought[18].

"When considering whether undertakings can act to an appreciable extent independently of their customers and competitors, Ofgem will look at a range of factors including:-

- customers' behaviour and options (for example, awareness of competition, the extent to which alternative providers are chosen, the extent to which substitutes are available)
- competitors' behaviour and capacities (for example, their range of offers, their ability to increase output within the relevant time period)
- market operation (for example, the extent of barriers to entry and exit)
- an undertaking's conduct in a market with regards to price setting as well as its financial performance (such as consistently earning a rate of profit significantly above competitive levels)
- market share"

"In Great Britain's gas and electricity sectors, due to the particular economic characteristics to be found there (including relatively inelastic supply and demand conditions), there are circumstances where undertakings may have the ability substantially and consistently to influence prices, and therefore to act independently of customers and competitors, even though their market shares fall below normal thresholds for considering dominance. This may particularly apply to markets for wholesale gas and electricity and to markets for capacity on gas and electricity networks".

There are no ex-ante mechanisms in place such as price caps to prevent the exercise of market power by generators. Ofgem adopts an ex-post approach to mitigating abuses of market power in electricity markets when it claims that "an investigation will focus on the commercial conduct of the relevant undertaking(s) and on the effects on customers of the conduct or agreements entered into by undertakings". If a market participant is found to have infringed UK or EC competition law, Ofgem has a range of remedies available to it including issuing an order to stop the behavior, and imposing a fine of up to 10% of the businesses' world-wide turnover. To address structural problems in power markets, Ofgem can also require generators to divest some of their assets.

[18] Ofgem 2005 http://www.ofgem.gov.uk/Markets/Archive/1505a%20-%20Competition%20Act%201998%20–%20Application%20in%20the%20Energy%20Sector%202701.pdf

Ofgem also has the power to propose conditions to generation (and other) licences. A licencee may accept, or object to, a condition; in the latter case the proposed condition is referred to the Competition Commission for arbitration. In 2000 Ofgem attempted to add a “market abuse licence conditions” (MALC) to the licenses of the seven largest generators in England & Wales. Market abuse was defined as an act that (i) prejudices the efficient and economical operation of the transmission system; (ii) limits generation capacity availability in such ways as to materially increase wholesale electricity prices which would have applied both to the physical withholding of capacity in service and the closure or mothballing of capacity that would be economic to operate; and (iii) pursue discriminatory pricing policies by determining wholesale prices that differ unduly between times when market demand and cost conditions are similar. Under the MALC guidelines, a license-holder was regarded as having a position of “substantial market power” if it had the ability to cause a “substantial change in wholesale electricity prices”, which was defined as an increase of 5% or more for a cumulative duration of more than 1,440 half-hours in any one year; or 15% over 480 half-hours in any one year; or 45% over 160 half-hours in any one year. The financial significance of these criteria was about £30m in 2000.

A breach of these conditions by a licensee would have resulted in an investigation by Ofgem and the possible imposition of the financial penalties cited above. While five generators accepted the condition, two base load generators objected to the Competition Commission which upheld their case (Ofgem made a poor case), and Ofgem withdrew the condition from all of the licenses.

Ofgem has a market surveillance team which monitors market prices of electricity and gas, and investigates unusual episodes such as price spikes. Ofgem further conducts investigations of companies that it believes may be acting anti-competitively or breaching consumer protection law.

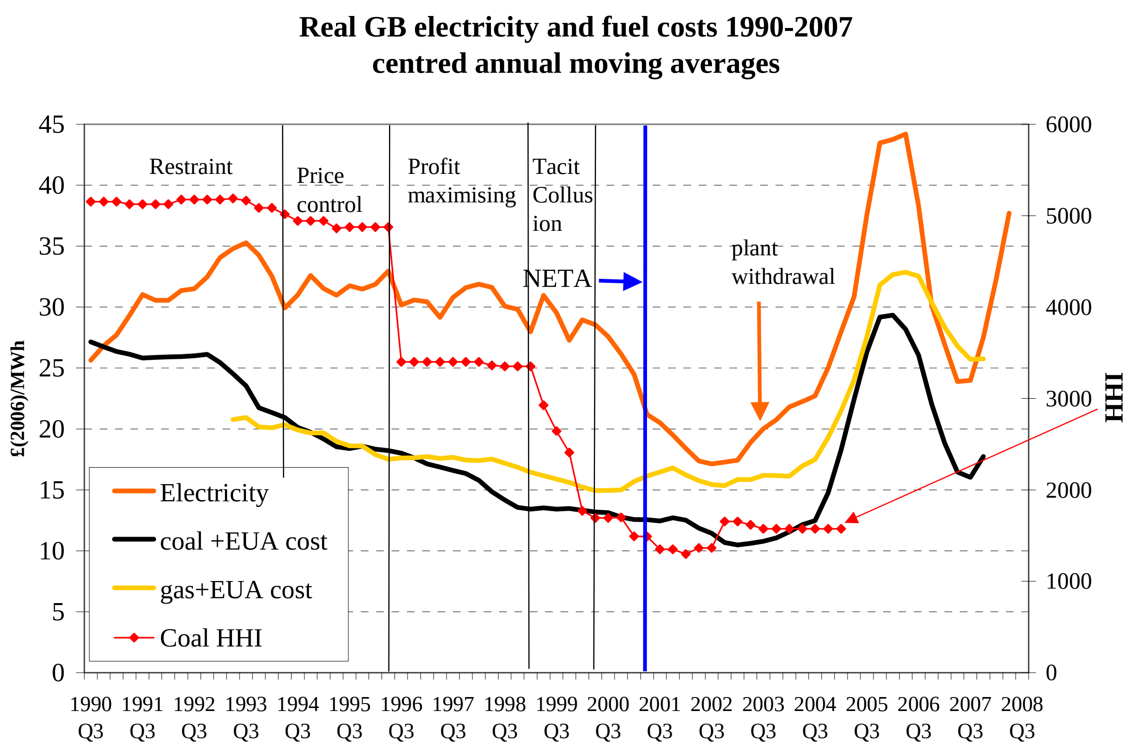
5.2 The way of the market and Ofgem’s response

Exhibit 1 shows the pattern of wholesale prices in England & Wales, then Britain[19]. Due to its ill advised attempt to privatize its nuclear power stations, the government restructured the electricity industry in 1990 with a large and dominant duopoly of price setting generators, National Power (29GW) and PowerGen (19GW). This structure resulted in continuing market power problems until 2000, when divestment and the completion of a number of merchant CCGTs fragmented the

[19] The market was extended from England & Wales to include Scotland in 2005.

generation market, and prices plummeted causing extensive financial distress to merchant generators. But early in this decade the electric industry both consolidated and vertically integrated, and once more market power is on the agenda.

Exhibit 1 Wholesale prices in England & Wales to March 2001, and then in Britain to end 2004



As explained in more detail in Annex 1, the regulator has made various attempts to limit the exercise of market power, but has not always been successful. The regulatory effort to counter market power can be divided into five phases:-

1. Various reports from 1990-93, which achieved little.

2. Price controls during 1995-96 from which the generators actually increased their profits, and divestment of 6GW by National Power and PowerGen which achieved nothing.

3. Further divestment in 2000, which together with the increase of merchant CCGTs coming on stream, fragmented the industry reducing the Herfindahl-Herschman Index[20] (HHI) reduced from 2200 in 1998 to 1170 in 1999-00, and reduced further to

[20] The HHI is calculated by taking the market share of each participant as a percentage, squaring it and summing each number to give the index. Thus a monopolist with a 100% share of the market will have a HHI of 10,000, while if there are 10 companies, each with an equal share of 10%, the HHI = 10 x 10 x 10 = 1000. Normally such a low HHI would indicate a very competitive market

670 in early 2001, and reduced prices. There was also an abortive attempt to introduce a Market Abuse Licence Condition.

4. The replacement of the Pool of England & Wales by the New Electricity Trading Arrangements, a bilateral trading arrangement with a net Balancing Mechanism in 2001. At considerable cost this change achieved nothing,

5. Ofgem then sat back and did nothing until the Business and Enterprise Committee of the House of Commons, stimulated in part by Energywatch, undertook its own report and prompted Ofgem to investigate the market. The House of Commons Committee was concerned that the UK's energy markets are not functioning as efficiently as they should, and the UK prices may be higher than those in competitor countries, and was critical of Ofgem. Ofgem published its investigation into the retail market, and will be publishing an investigation into the wholesale markets.

At the beginning of this decade the authorities – basically the government more than Ofgem – allowed the electricity industry to consolidate into six largely vertically integrated companies to create an oligopoly. And in 2008, as a consequence of government dithering over British Energy and the role of nuclear power, it has further consolidated the industry by allowing EDF Energy to buy a three quarter interest in British Energy so that it will produce about a fifth of the power generated. The fact that Parliament shamed Ofgem into undertaking an investigation of the market is an indication that there is a strong view that market power is possibly alive and well.

6. ALBERTA

Alberta is a small market with some 1.3 million meter points and an annual consumption of 50TWh. In 1996 a form of competitive restructuring was introduced with a gross Pool[21] and third party access to transmission; the market was an energy only market. But the industrial structure was not promising; all plant was owned by three companies (TransAlta, Atco and EPCOR), and legislated hedges (i.e. contracts for differences) were put in place which essentially grandfathered the historic output of the generators and consumption of the customers, leaving only changes at the margin being exposed to Pool prices.

Three market power mitigation mechanisms are of interest in Alberta, the virtual power plant auctions; the style of the Market Surveillance Administrator; and the forthcoming regulation on ensuring “Fair, Efficient and Open Competition”.

6.1 The virtual power plant auctions

Pool prices were low in 1996 and 1997 and, although the system was tightening rapidly, no new plants were being built. The government became concerned about the capacity situation and that the legislated hedges may be having unintended consequences. It commissioned consultant London Economics, Inc. to consider “Options for Market Power Mitigation in the Alberta Power Pool”. In January 1998 the consultant came up with the novel approach of (what is now known in Europe as) auctioning “virtual power plants”, i.e. the sale of long term firm power purchase agreements (PPAs) to “marketers”. This arrangement would on the one hand continue to allow the plant owners to recover the embedded costs of their generating units (which was the regulatory compact under which they were built) by using the proceeds of the auction (and a levy if needed) to remunerate the plant owners, and on the other hand gives the marketer the exclusive right to offer the plant into the Pool and instruct the generation owner as to its operating schedule, subject to pre-determined constraints on minimum on and off-times, ramp rates, maintenance requirements, etc.

Among other things the Electric Utilities Amendment Act 1998 empowered the government to introduce the auctions and set up the “Balancing Pool” to receive the income from the auction and to assume responsibility for any contacts that were not sold. In 2000 Alberta’s generation plants were

[21] The Pool was subsequently operated by the Alberta Electric System Operator. To reduce the number of names it is always called “the Pool”.

grouped into 12 PPAs- TransAlta offered 5 totaling 3300MW; Atco offered 4 totaling 1600MW; and EPCOR offered 3 totaling 1600MW. The contracts were for the shorter of the regulated accounting life of the plants or until 2020. In broad terms the contracts consist of four main elements:-

- the generation owner would be paid an availability payment for every hour the unit was available. Payments could be sculpted seasonally and daily to ensure that the generator was under maximum incentive to keep the unit available in peak price periods. There would be a penalty payment structure to allow the marketer to enter into a reasonable contracting position without undue exposure from unit forced outages. The sum of expected availability payments (based on target levels of maintenance requirements and forced outages) would be equal to the generator's expected fixed (embedded) costs on the unit

- the generator would be paid a variable charge for each MWh generated. This would be calculated as the fuel cost (indexed) times the target heat rate times the number of kWh actually produced. The use of a target heat rate gives the generation owner strong incentives to maintain or better the existing thermal efficiency of thermal units

- fuel and labour costs were indexed

- some cost elements (such as local property taxes, environmental taxes, etc) which are outside the effective control of the generation unit owner are passed through

The contracts also contained explicit incentives to encourage plant operators to strive for operational efficiency and maximum availability of their generation capacity. For instance, energy in excess of the contractual obligation to the PPA owner would belong to the owner of the plant and be available to be offered into the Pool.

The auction was conducted over a three-week period as a series of ascending price-bidding rounds with four to six rounds per day. Bidding was simultaneously open on all PPAs in each round and was conducted using a secure Internet site. The number of firms that registered for the auction was almost identical to the number of PPAs that were for sale, and was probably close to the minimum that the government would have accepted without withdrawing the auction. With so few bidders the competition for each PPA was limited and prices were low. A total of eight PPAs were sold to 5 separate firms at low prices, see exhibit 2, leaving 4 contracts with a capacity of 21701MW with the Balancing Pool.

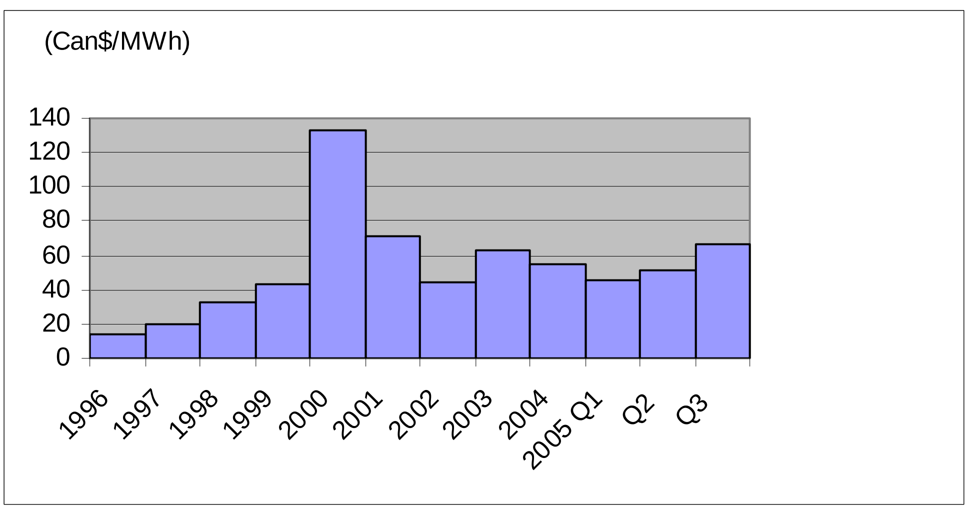
Exhibit 2 PPAs offered for sale in August 2000

	Capacity (MW)	Winning bidder
Battle River	666	EPCOR
Keephills	762	ENMAX
Rainbow	93	Engage
Rossdale	208	Engage
Sundance A	560	TransCanada
Sundance B	706	Enron
Sundance C	710	EPCOR
Wabamun	549	ENMAX
Total sold	4254	

Subsequently the Balancing Pool auctioned short term strips, which were sold in two rounds, the first of 1 year strips, the second of 3 year strips which were sold to a further 10 companies. A third auction offered multiple strips or the entire power purchase agreement for sale; the Sheerness power purchase agreement of 750MW was sold in entirety to TransCanada Corporation. These subsequent auctions were at much higher prices.

The auction reduced the HHI of generation from about 3500 in 2001 to about 750 in 2001, and thus contributed to creating a competitive market with falling prices, as the plot for 2001 show in exhibit 3.

Exhibit 3 Yearly average real-time wholesale market price



6.2 The Market Surveillance Administrator (MSA)[22]

The 1998 Act also created the MSA as part of the system operator; the 2003 Act established it as an independent entity which undertakes the following activities:-

- Conducts general surveillance of the electricity market
- Reviews and, if deemed necessary, investigates irregular market behaviour
- Provides information and analysis on market fundamentals
- Advances market policy
- Minimises market information asymmetry
- Discharges compliance audits
- Acts as advocate for market stakeholders

On a routine basis the MSA reports on:-

- Scheduled generation outages
- Plant actual outages
- Weekly market performance

It also prepares quarterly reports on its activities and the market; publishes an annual "Year in Review"; and undertakes ad-hoc investigations into market issues.

In a report "Undesirable Conduct and Market Power, July 2005" it set out its views on market power as follows:-

> "Different electricity markets have defined the concept of market power in subtly different ways. In order for the concept to have meaning in the context of the Alberta electricity market, we take direction from section 6 of the Electric Utilities Act that places a requirement on participant's conduct:-
>
> > Market participants are to conduct themselves in a manner that supports the fair, efficient, and openly competitive operation of the market. [*This statement is the touchstone of the MSA's analysis, and is defined in the Act]*.
>
> We thus define market power as:-
>
> > Market power: means the ability, whether exercised or not, to materially affect the fair, efficient and openly competitive operation of the market.
>
> One type of undesirable conduct we distinguish is the abuse of market power:-
>
> > Abuse of market power: means conduct that may be reasonably foreseen as likely to materially undermine the fair, efficient and openly competitive operation of the market".

[22] www.albertamsa.ca

The MSA has undertaken investigations of:-

- Spinning Reserve Market Event Report, January 2004. This report identified shortcomings in the Hydro PPA between TransAlta and the Balancing Pool that allowed TransAlta to manipulate the contract to the detriment of the reserve market as a whole. The MSA observed "When market outcomes cannot be tied to market fundamentals and there are perverse outcomes, confidence in that market is eroded". It concluded that:-

  > "The spinning reserve market has experienced anomalous market outcomes for reasons that do not appear consistent with a fair, efficient and openly competitive market. A key concern for the MSA in this matter is the impact that such anomalous outcomes may have on the confidence of market participants that the ancillary services market is a properly functioning market. For example, the standard market response to a shortage of supply is a rise in the market price which signals scarcity. In this case, the price signal [which had decreased] is counterintuitive".

  The MSA requested the Balancing Pool and TransAlta to modify their agreement to address its concerns and they entered into a new agreement that came into effect on 1 August 2004. "Since its signing, more rational market clearing prices that better reflect competitive forces have been observed".

- The MSA initiated an investigation into problems with transmission must run contracts (TMR)[23] in October 2004. The MSA undertook the study because "There is currently a low level of confidence in the market for TMR". There have been numerous references to the regulator seeking changes to the arrangements, including termination of a recent approved contract and a long running contract dispute between ATCO and the Pool. "The MSA's interpretation of the debate between the parties about the pricing methodology is that this is essentially one of disagreement about whether pricing should be based on energy market outcomes adjusted for any operation that is uneconomic, or as a substitute for a long term regulated transmission assets. This is a relatively simple but key philosophical issue, and goes to the heart of an assessment of the pricing principles that might apply for these arrangements:-

  * in the past, TMR was considered as a long-term substitute for transmission, and this logically lead to the use of a long-term regulated cost of service approach that was potentially unrelated to energy market returns
  * however, as the market was deregulated, and in part as a result of a poorly designed contract structure, TMR providers received revenues well in excess of regulated returns, prompting a review of TMR pricing arrangements by the AESO and the current application for a review of the TMR pricing arrangements before the Alberta Energy Utilities Board

The MSA commissioned Charles River Associates to study the issues[24] and supported many of the consultant's conclusions, observing:-

---

[23] i.e. a contract between the Alberta Electric System Operator and a generator that must run for constraint or stability reasons.

[24] MSA Report, Transmission Must run Investigation, February 2005; Transmission must run, submitted to Market Surveillance Administrator, prepared by Charles River Associates (Asia Pacific) Pty Ltd, March 2005.

- The Pool's internal processes, at least as presented to external parties, have not been as assertively competitive as is possible

- There is a lack of formal processes for selection of TMR procurement, and a preference for bilateral negotiations with identified counterparties

- It is not clear whether in general the Pool has distinguished sufficiently between its own view of the preferred provider, and how a competitive procurement process should best be managed in practice, and in the interests of openness, transparency and revelation of information, be seen to be managed. This has led to an ad hoc process for considering the tradeoffs involved

- The Pool's assessment of what constitutes reasonable and prudent payment for TMR services appears to be based on short–term cost minimization objectives, rather than on an even-handed or rigorous analysis and its wider promotional role with respect to fair, efficient and openly competitive markets

- In response to what may have been legitimate monopoly supplier concerns in the Rainbow Lake area, the Pool adopted a range of increasingly heavy-handed quasi-regulatory measures to conscript TMR services and develop associated pricing provisions aimed at protecting customers

The MSA made a number of recommendations calling on both regulator and the Pool to alter practices especially improving transparency regarding the contracting of TMR contracts and calling them, and that it would monitor the use of non-competitive processes by the Pool.

The MSA has in hand an ongoing investigation into an allegation that ENMAX, which had sold more power than it could generate or had contracts for (i.e. it was short generation), attempted to reduce (i.e. manipulate) the Pool price by importing power through the intertie with British Columbia to dump it in Alberta[25]. Although such a reduction would have been in the interest of consumers, the MSA took the view that the company's alleged actions not only contravened the principle of a fair, efficient and openly competitive market, it was equally possible that another party could push prices up by exporting "excessive" power.[26]

[25] Power from the intertie is priced at zero. Importing power reduces the in-Alberta stack.
[26] http://www.albertamsa.ca/files/Market_Concentration_Metrics.pdf.

6.3 Draft Fair, Efficient and Open Competition Regulation

In a White Paper published in 2008 the Department of Energy of the government of Alberta observes that[27]:-

> "A fundamental aspect of a competitive market is that participants are afforded the opportunity to act in their self interest and realize profits (and losses) on their investments, through interaction and competition with other participants. This essentially was recognized by one of the Section 6 Committee's principles of participant conduct and is a principle supported by the Department. It is equally important to recognize that in any market some activities clearly are unfair or anti-competitive, such as fraud, collusion and the abuse of market power".

The Department of Energy has now published a Draft "Fair, Efficient and Open Competition Regulation", see Annex 2, which in section 2 defines "Conduct not supporting fair, efficient and open competition" as follows:-

- Providing deceiving or misleading records to any other market participant
- Misrepresenting the financial condition of the market participant to any other market participant
- Arranging offsetting or wash trades involving the market participant and one or more other market participants, or through third party arrangements, which when completed, collectively do not result in any material financial risk and no net change in beneficial ownership
- Representing to the market, or to any other market participant, that electricity, electric energy, electricity services or ancillary services are available when they are not
- Misrepresenting the capability or operational status of a generating unit, transmission facility or electric distribution system
- Not offering all electric energy from a generating unit that is capable of operating into the power pool or for the provision of ancillary services, except where the electric energy is used on property for the market participant's own use or to the extent the ISO rules do not require the electric energy or ancillary services to be offered
- Disrupting or impairing the safety or reliability of the interconnected electric system
- Restricting or preventing competition, a competitive response or market entry by another person, including :-
    - any collusion between a market participant and any other market participant or any signaling strategy by a market participant with regard to offer strategy, allocation of market share, market territory, customers or other participation in the market

[27] White Paper on implementation of policy enhancements supporting section 6 of the Electric Utilities Act and Alberta's fair, efficient and openly competitive electricity market, Alberta Department of Energy, 8 January 2008.

* predatory conduct

* other conduct to discipline or exclude any competitor or anticipated competitor

- Offering electric energy from a generating unit, or operating a generating unit, transmission facility or electric distribution system in an uneconomic manner for the purpose of:-

  * creating or increasing congestion
  * being paid to relieve that congestion

- Manipulating market prices, including any price index, away from a competitive market outcome

- Carrying out actions or transactions to circumvent any enactment, order or decision of the Commission, ISO rule or other rule applicable to a market participant

In addition it bans:-

- Preferential Information Sharing: Market participants shall not preferentially share proprietary information which may reasonably be expected to undermine or prevent competition

- Restricts trading using outage records that are not available to the public

And it limits control (whether by ownership or contract) of generation and imports to 25% of total capacity available on the system.

7. MARKET POWER MITIGATION IN SOME US POWER MARKETS

The Federal Energy Regulatory Authority (FERC), which regulates wholesale markets in the US other than in Texas, was scarred by the crisis in California of 2000-01, which led to a far more interventionist approach to market power mitigation than is practiced elsewhere. To provide the context the first section summarises what happened in California. This provides the lead to FERC's approach to mitigating market power. Then we look at the market power mitigation practices in the three longest running markets (apart from California), namely those in the energy markets[28] of New York, New England, and the PJM, and the Texas market which is not regulated by FERC.

7.1 THE CRISIS OF MARKET POWER IN CALIFORNIA[29]

The deregulated[30] market in California has an annual consumption of about 230TWh p.a. The market started functioning on 31 March 1998 as an energy only market with no price cap. When the major companies were induced to divest their plant they were not allowed to sign contracts with them to supply the retail load for which they would remain responsible. As a result the generators were unconstrained by contracts, and the utilities were buying short on the Power Exchange to supply long for the tariffs set by California Public Utilities Commission.

The main reason for the crisis in the Californian power market from the summer of 2000 to the summer of 2001 was the exercise of market power by physical and economic withholding by generators. During May 2000 demand increased with the warmer weather, but a nuclear power plant was out and supplies from outside California decreased, and generation costs increased due to higher gas prices and NO_x emissions permits (both in significant part due to price manipulation in these markets, see below). Demand moved up the supply curve to the point where it rises steeply, and provided the incentive to generators to withhold supply. They exploited the possibilities ruthlessly, breaking the market rules of the California Independent System Operator (CAISO) with impunity. The generators:-

[28] There are also mitigation practices in the ancillary services and capacity markets, but to retain focus on the main issue and because there is no capacity in the National Electricity Markets, these are not examined.
[29] The material in this section is based largely on "Final report on price manipulation in western markets, fact finding investigation of potential manipulation of electric and natural gas prices", Docket No. PA02-2-000, Prepared by the Staff of the Federal Energy Regulatory Commission, March 2003.
[30] The deregulated market does not include the municipalities, coops and some federal entities. The total annual consumption in California is about 280TWh.

- Physically withheld generation, creating false shortages and scarcity:-

    * generators falsely reported to the CAISO that generating units were forced out of service for mechanical reasons when the plants own records showed that they were capable of normal operation

    * on over 20 occasions, totalling over 350 hours during times when the CAISO had declared a system emergency, generators placed units on "reserve shutdown" - that is, they simply shut the plant down for what they asserted to be economic reasons when no maintenance was required

    * not bidding their output into the market even though their plants were fully operational -- again, often during system emergencies

- Economically withheld generation by bidding so high that they deliberately priced themselves out of the market. Often, generators and suppliers bid far higher after the CAISO declared a system emergency, knowing that it would need all available power and would be willing to pay any price to get it

These withholding strategies - often involving more than the 1,000 MW of capacity – succeeded for some periods in keeping the market in a near constant state of shortage (even during periods of low demand) and the CAISO near to panic as it was forced to fight against time to obtain the power needed to keep the lights on.

Traders manipulated the markets in illegal ways, such as false reporting of trades, wash trading, and manipulation of trading at times that are important for the construction of indices to which derivatives are linked. Some of the tricks that traders played in California were:-

- Scheduling bogus load. Some traders submitted false load schedules to increase scarcity and prices in the day-ahead market and to move resources into the more easily manipulated real-time markets. The "Enron Memos"[31] referred to this strategy as "Fat Boy" or "Inc-ing Load" and called it the "oldest trick in the book"

- "Ricochet"-type export-import games or "Megawatt Laundering". Generators and power marketers created artificial scarcity and reliability concerns by exporting vast amounts of power out of California on a day-ahead basis in order to import the same power back into California in an attempt to sell at inflated prices into the real-time markets or under "Out-of-Market" agreements with the CAISO, which were not subject to a California price cap

- "Death Star" and other congestion games. Numerous market participants pursued Enron-type congestion games, such as circular export-import schedules (Death Star) which resulted in

[31] The Enron Memos are a series of memos by Enron staff describing a variety of trading "strategies" that the company adopted. FERC released the memos onto a website http://www.ferc.gov/cust-protect/disclosure.asp.

payments for congestion relief by creating fictitious congestion and fictitious counter-flows, without actually moving any power or relieving any congestion. These games resulted in reliability problems, higher zonal prices, and payments for the relief of congestion that never existed and, consequently, was never relieved

The market power in the electricity market was exacerbated by:-

- Manipulation of the gas market for supplies into California where there was:-

  * price manipulation
  * withholding of gas supplies
  * wash trading through EnronOnLine
  * manipulation of price reporting data

- Manipulation of the NOx emission market. Evidence suggests that Dynegy, together with AES and others, entered into a series of wash-trades of NOx credits at inflated prices in July and August 2000[32]

During the summer and the autumn of 2000, while prices soared, the California Public Utilities Commission, the Governor and the legislature, were like rabbits caught in a vehicle's headlights and did nothing except prod the Federal Energy Regulatory Commission (FERC) to restrain wholesale prices to be "just and reasonable". For its part, on 1 November FERC released a report by its staff on the California market and a Proposed Order[33]. It laid blame on the Californian authorities, called the wholesale market structure "seriously flawed", and made proposals to change market rules. While it agreed that findings by the Market Surveillance Committee "certainly suggest that market power was exercised in June", it concluded that the evidence it analysed during its investigation was inconclusive in determining whether individual sellers exercised market power. It was not prepared to take any aggressive remedial action during the final lame-duck months of the Clinton Administration.

With rotating blackouts, the filing of Pacific Gas & Electric for chapter 11 bankruptcy and the near demise of Southern Californian Edison, the State had to step in. The governor ordered the Californian Department of Water Resources to buy power. Eventually prices collapsed from the end of May 2002

[32] Dynegy would sell a large quantity of NO_x credits and then simultaneously buy back a smaller quantity of credits at a higher per credit price. The net effect of the transactions was that virtually no money changed hands, but resulted in the reporting of sales at inflated prices, increasing the apparent cost of NOx credits, and, therefore, the apparent marginal cost of electric energy.

[33] "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities, Part 1 of Staff Report on U.S. Bulk Power Markets", 1 November 2001, Federal Energy Regulatory Commission.

and the inquests began. In March 2003 FERC Staff issued a report which set out most, if not all, of the story[34].

The reference to the California experience is important both as a background to how the US approach to mitigating market power subsequently evolved, and also as a warning to what may happen if there are inadequate means to mitigate market power.

7.2 FERC'S APPROACH TO MITIGATING MARKET POWER

The Federal Power Act, under which FERC functions, is a regulatory statute, not an antitrust law, and was not ideally suited for restructuring electricity markets. Its primary regulatory goal is the attainment of *"just and reasonable prices"*, not the prevention of competition. Sections 315 and 1283 of the Energy Policy Act of 2005 amended the Federal Power Act prohibit the use or employment of "manipulative or deceptive devices or contrivances in connection with the purchase or sale of natural gas, electric energy, or transportation or transmission services subject to the jurisdiction of FERC". FERC has implemented the Act through its Order No. 670[35]. Under the Act FERC is authorized to impose civil penalties of up to $1 million per day for each violation of rules, regulations, and orders, and the ability of FERC to seek criminal penalties against those who willfully manipulate energy market prices has also been expanded.

Market power is abused in electricity markets when it is exercised beyond allowable levels or benchmarks, resulting in prices that are not considered *just and reasonable.* Courts have determined that an unjust and unreasonable rate is one that falls outside the zone of reasonableness, where that zone excludes rate levels that are "less than compensatory" to producers or "excessive" to consumers. That is, on the one hand, rates should be high enough to give producers a reasonable opportunity to recover their costs, including a risk-adjusted return on capital, but sufficiently low to avoid consumer harm.

FERC learnt some hard lessons from the experience in California, and subsequently its ability to address market power abuse and manipulation resulting in prices which are not just and reasonable

[34] Op. cit.
[35] Prohibition of Energy Market Manipulation, Docket No. RM06-3-000, Order No. 670, Issued 19 January 2006. http://www.ferc.gov/enforcement/market-manipulation.asp.

has evolved. FERC's Standard Market Design Notice of Proposed Rulemaking (NOPR)[36] and its White Paper "Wholesale Power Market Platform"[37] of April 2003 by FERC Staff reflected the bitter lessons from California. Both documents were very strong on market power mitigation measures. In the NOPR "FERC finds that wholesale electric markets are not yet structurally competitive in all respects. Specifically, FERC identifies the lack of price-responsive demand and generation concentration in transmission-constrained load pockets as two structural flaws in these markets, which create the potential for participants to exercise market power, defined as the ability to raise price above the competitive level[38]. FERC proposes new market power mitigation measures to deal with the consequences of these defects by approximating the outcomes that a competitive market would produce. These measures will be implemented by the Market Monitoring Unit, an entity that will report directly to the FERC and to the independent governing board of the Independent System Operator/Regional Transmission Organisation (ISO/RTO) the results and recommendations derived from its study of the markets operated by the ISO/RTO".

"The Market Monitoring Unit will focus on the functioning of the ISO/RTO's markets, the conduct of individual market participants and on identifying factors that might contribute to economic inefficiency. FERC intends to require the use of a core set of questions and analytical techniques to be used by each Market Monitoring Unit to assess market structure, participant behavior, market design and market power mitigation, which will facilitate inter-regional comparisons. At a minimum, the Market Monitoring Unit would be required to submit an annual report that would include: (1) a general description of the market operations, supply and demand, and market prices; (2) an analysis of market structure and participant behavior; (3) an evaluation of the effectiveness of mitigation measures taken; (4) an overall assessment of market efficiency perhaps using a simulated competitive benchmark; (5) an evaluation of barriers to entry for generating, demand-side and transmission resources; and any recommended changes to market design or market power mitigation measures to improve market performance. In addition, the Market Monitoring Unit will be required to report to FERC, through the Office of Market Oversight and Investigation, any instances of conduct by market

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[36] Docket No. RM01-12-000, 31 July 2002.

[37] http://www.ferc.gov/industries/electric/indus-act/smd/white_paper.pdf.

[38] In its "Guide to Market Oversight", FERC defines market power as "the ability of any market participant with a large market share to significantly control or affect price by withholding production from the market, limiting service availability, or reducing purchases[38]." In its Citizens Power & Light and CAISO MRTU orders, FERC defines market power as a "seller's ability to significantly influence price in the market by withholding service and excluding competitors for a significant period of time[38]."

participants that appear to be inconsistent with the Standard Market Design Tariff[39]. As set forth in the Standard Market Design Tariff, market participants and transmission customers will be required to agree to predetermined penalties that would apply to violations of the tariff rules".

Generators in the US had often claimed that the difference between price and marginal cost is a "scarcity rent," and not the result of market power abuse, and that such scarcity rents are necessary and proper to remunerate peaking (and other) plant adequately. *But as FERC staff are clear, it is difficult to separate scarcity conditions from the exercise of market power because scarcity conditions must give generators market power.* The report by the staff of FERC on the California crisis dealt unambiguously with this issue as follows:-

> "It is difficult to separate scarcity from market power…during periods when electricity becomes more scarce, the price naturally increases. However, during those same periods the ability and incentive to exercise market power increases. The ability to exercise market power (raise price) increases because the market is clearing in the steep (inelastic) portion of the supply curve, thus a slight reduction in output will significantly increase the market-clearing price. The incentive to exercise market power increases because the payoff becomes much higher".

FERC does not have the authority to impose structural remedies (*e.g.*, divestiture) to address unilateral or multilateral market power, and US antitrust authorities rarely succeed in imposing structural remedies (outside of merger cases). As a consequence, there is widespread recognition that some level of *ex ante* mitigation of market power is advisable, which is demonstrated in the US markets considered in this paper.

The White Paper "Wholesale Power Market Platform" said that "the ISO/RTO must address economic withholding in the spot markets by implementing market rules that act to limit spot market bids, before the settlement price takes effect. This is preferable to letting spot markets work initially without restraint, then trying to detect bad behaviour after the fact, and later making amends by trying to determine what the correct market prices should have been. Before-the-fact market power mitigation in energy spot markets may consist of either or both of:-

- Offer caps, offer thresholds, contracts, or other limits that are for specific generators, locations, or conditions

[39] An ISO/RTO Tariff is a very broad document that defines both regulated rates (e.g. network access charges) and the principles that will underly market based rates including any constraints such as price caps.

- a safety net offer cap that applies to all generators at all times". *In effect FERC requires a cap of $1000/MWh on offers*

FERC's approach is to aim to mitigate the exercise of market power in the day-ahead and real time energy markets so that prices approximate system marginal cost. The income from their energy markets will not recover income necessary to remunerate generators' investment, so in addition there is income from a capacity market and ancillary services which together remunerate investment in generation.

The rules governing organized US wholesale electricity markets typically do not directly define the term "abuse of market power." Instead, they tend to identify either structural conditions conducive to the exercise of market power or specific practices (*e.g.*, economic or physical withholding) that must be mitigated. Under this indirect definition of market power abuse, most US RTO tariffs require the mitigation of practices that "substantially" or "unreasonably" distort or impair the competitiveness of any of the markets which they administer[40]. Moreover, none of the RTOs define a "bright line" as to what constitutes a substantial or unreasonable distortion of competition.

7.3 THE MARKET MONITORING AND MARKET POWER MITIGATION ARRANGEMENTS IN THE ENERGY MARKETS OF NEW YORK, NEW ENGLAND, PJM AND TEXAS

The three markets have the common features that they are all broadly the Standard Market Design, with a day ahead energy spot market and a real time energy spot market; are based on locational marginal pricing; have a capacity market of some sort[41]; and they all come under the jurisdiction of FERC.

The New York ISO (NYISO) and New England ISO (ISO-NE) both have internal market monitoring units, and also an external market advisor who serves at the pleasure of the respective board but also reports to FERC. In both cases the external advisor is Potomac Economics. The internal and external market monitoring units have access to any information they require. The PJM has an internal Market Monitoring Unit which reports to the board of the PJM and to FERC. Recently a conflict between the

[40] Only the Electric Reliability Council of Texas (ERCOT) explicitly categorizes such conduct as an abuse of market power.

[41] The addition of a capacity market does not per se mitigate market power in the energy market. But what it does is to provide is a supplementary income stream that means that a generator will recover adequate revenue to remunerate its investment if the energy market is mitigated to pricing at system marginal cost.

Market Monitor and the Chief Executive was part of the reason the Chief Executive was invited to take early retirement and clear his desk at very short notice.

While PJM's "Market Monitoring Plan" defines one of the "Monitored Activities" as "[t]he potential of any Market Participant(s) to exercise undue market power", the other ISOs do not define abuse of market power but describe the types of conduct that they will mitigate. NYISO states that it is mitigating conduct which *"would substantially distort or impair the competitiveness of any of the ISO Administered Markets"*; ISO-NE notes in its tariff that it will mitigate conduct that "*would substantially distort or impair the competitiveness of any of the markets administered by the ISO"*.

As will be seen from the following descriptions, apart from the common price cap of $1000/MWh in the energy market, the approaches to ex-ante market power mitigation in the three markets are significantly different. Namely the NYISO and ISO-NE use a conduct and impact approach both for the general market and import constrained zones, while PJM has no mitigation in the general market and uses a screen and cost based offers in constrained areas. But in assessing the overall structural situation of the market power, they all use:-

- **HHI** as a measure of concentration. The "Merger Policy Statement" of the FERC states that a market can be broadly characterized as:-

  * unconcentrated. Market HHI below 1000, equivalent to 10 firms with equal market shares
  * moderately Concentrated. Market HHI between 1000 and 1800
  * highly Concentrated. Market HHI greater than 1800, equivalent to between five and six firms with equal market shares

  These criteria are also used as a framework to judge the concentration of electricity markets, but they are imprecise. A low concentration index does not guarantee that a market is competitive, but higher values are indicative of greater potential for the exercise of market power.

- **The residual supply index**[42] **(**RSI) or residual demand index (RDI) is a measure of the extent to which a generation owner is a pivotal supplier. A generation owner is pivotal if the output of the owner's generation facilities is required in order to meet market demand; it then has the ability to affect market price. When the RSI is less than 1.00, a generation owner is pivotal. If two generators are required to meet market demand they are said to be "jointly pivotal"; PJM use a

[42] The residual supply index measures the percentage of load that can be met without the largest generator and is computed as RSI = (total supply minus largest seller's supply)/(total demand). The RSI measures the potential for individual offerors to influence the market-clearing price. If the RSI exceeds 1.0, then alternative generators have sufficient capacity to meet demand. If, however, the RSI is below 1.0, a portion of the largest generator's capacity is required to meet market demand and the generator is "pivotal" and can unilaterally drive price above the competitive level, subject to prevailing offer caps. Studies conducted by the California ISO suggest an inverse relationship between the RSI and the price-cost mark-up.

> three generator pivotal metric for load pockets, which is more stringent. As a structural indicator, it does not illuminate actual supplier behavior, indicating whether a supplier may have exercised market power. The RDI also does not indicate whether it would be profitable for a pivotal supplier to exercise market power. However, it does identify conditions under which a supplier would have the *ability* to raise prices significantly by withholding resources

They also all use the **price-cost markup index** as a means of measuring post hoc the level of exercise of market power. The mark-up is the difference between price (P) and marginal cost (MC), divided by price, where price is determined by the offer of the marginal unit and marginal cost is derived from the highest marginal cost unit operating. The markup index (P – MC)/P is load-weighted to account for congestion and then normalized. The price-cost mark up index is computed using a simulation.

ISO-NE defines the relevant geographic market as the entire ISO, while the NYISO and PJM define the relevant market as a constraint or set of constraints prone to market power problems. These constraint-based market definitions all recognize that generating resources located generally on the receiving side of constrained transmission elements can relieve the constraint by increasing their output while those on the sending side can relieve the constraint by decreasing their output.

7.3.1 The automated mitigation procedure in New York[43]

The market operated by the NYISO covers the State of New York, which has a population of 19.2m customers and an annual consumption of about 167TWh. Its main market power problem is in New York City, which has few sellers (HHIs range from approximately 2,100 to 5,600) and little surplus capacity.

There is a cap of $1000/MWh on generators’ price offers. NYISO uses a two step approach to market power mitigation, checking first the *conduct* of a generator in making offers, and second analyzing the price *impact* of the offer. The decision as to whether to mitigate is carried out automatically by a program which checks for offers that are outside of established limits, and if so whether an offer would have a significant impact on the market price or payments to the generator. For New York State (excluding New York City and Long Island) the conduct threshold is an offer that exceeds a reference level by the lesser of $100/MWh or 300%, and the price impact threshold is an increase in the market price of the lesser of $100/MWh or 200%.

[43] NYISO’s website may not be accessible from Australia.

The Automated Mitigation Procedure uses a computer program to check thresholds automatically and to calculate the impact. If the answer to both questions is yes, and the seller does not have an acceptable explanation of the offer, then the offer will be mitigated to a "reference level", and the original offer will not affect the determination of the market price. Reference levels are normally set by calculating the average fuel adjusted accepted offer of a generator over the last 90 days during comparable periods where there is reason to believe most offers will have been subject to competition. If there are insufficient offers meeting these conditions, the generator may submit documented evidence of marginal operating costs from which a reference level is calculated.

New York City poses particular problems; special mitigation procedures go into effect when transmission lines into the City and/or within will be congested in the day-ahead and real-time markets. The thresholds in New York City are much lower than in the rest of the State, being determined as a function of the frequency of transmission constraints into a specific load pocket, and are inversely proportional to the non-congested hours experienced over the preceding twelve month period. The conduct and impact thresholds vary in a range of $3.3/MWh to $40.4/MWh between the day-ahead and real time markets. An in-City offer will be mitigated if it exceeds the reference level by the threshold and the offer has a comparable impact on market price.

The Independent Market Advisor reported for 2007[44] "We find that the markets performed competitively in 2007. We found little evidence that suppliers were either economically or physically withholding resources to raise energy or ancillary services prices in the market…In certain constrained areas, most of which are in the New York City area, some suppliers have local market power because their resources are needed to manage congestion or satisfy local reliability requirements. In these cases, however, the market power mitigation measures effectively limit their ability to exercise market power."

The only competitive concern identified in the NYISO markets relates to the results in the installed capacity market. In both 2006 and 2007, a significant amount of existing capacity did not clear in the capacity market due to high capacity offer prices. This conduct maintained capacity clearing prices in New York City near the cap for divested generation owners in the City. These prices are substantially higher than the prices that would have prevailed if all capacity had been sold, which raises significant

[44] http://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2007_SOM_Final.pdf

competitive concerns. However, the New York ISO filed mitigation provisions to address these competitive concerns in October 2007 that were approved by the Commission in March 2008.

7.3.2 Market power mitigation in New England[45]

The market operated by the ISO-NE covers the six New England States, Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. The population of the region is 14m, and the consumption/production of electricity is about 135TWh p.a.

Market Rule 1, Appendix A, Market Monitoring, Reporting and Market Power Mitigation[46], provides for the monitoring and, in specifically defined circumstances, the mitigation of behavior that interferes with the competitiveness and efficiency of the energy, regulation, reserve markets, and the market for financial transmission rights. As specified in the rule, ISO-NE monitors offers for the market impacts of specific offering behavior. Whenever one or more of a participant's offers or declared unit characteristics (1) exceed specified offer thresholds, (2) exceed market impact thresholds, and (3) are not explained by the participant as consistent with competitive offer behavior, the ISO substitutes a competitive offer in place of the offer submitted by the participant. Mitigation measures may be applied to generation offers, demand bids, virtual offers, virtual bids, and offers relating to installed capacity, as well as to the scheduling or operation of a generation unit or transmission facility. The principle applied is that a participant's conduct is "inconsistent with competitive conduct if the conduct would not be in the economic interest of the Participant in the absence of the ability to affect market price".

The mitigation procedure is a three step process:-

1. Prior to the day-ahead clearing process and after the re-offer period, ISO-NE calculates the residual supply index for the whole market, and designates any pivotal suppliers for each hour in the day-ahead market and the real-time market

2. After the offer windows close at 12:00 and 18:00[47] ISO-NE undertakes a "conduct test" by comparing generator offers to reference levels. Offers that exceed the reference levels by more than the threshold value are deemed to fail the conduct test. There are different thresholds above the reference levels for the general and constrained area screens. The general thresholds and mitigation authority apply to any identified pivotal supplier portfolios, and the constrained

[45] ISO-NE's website may not be accessible from Australia.

[46] The Market Power Mitigation method is included in ISO-NE's FERC Electric Rate Schedule No. 7, see http://www.iso-ne.com/smd/market_rule_1_and_NEPOOL_manuals/Market_Rule_1/MR_1_Appendix_A_-_Market_Monitoring/

[47] A unit that does not clear in the day-ahead market (12.00hrs offer deadline) is allowed to revise its offers at 18.00hrs.

area thresholds and mitigation authority apply to all generating units when the transmission system is constrained:-

- General thresholds – ISO-NE investigates the reasons for any offers from a pivotal supplier that exceed the following thresholds:-

  * Energy offer price: a 300% increase or an increase of $100/ MWh above the reference level[48], whichever is lower
  * Startup and no-load offer price: a 200% increase above the reference level
  * Regulation offers: a 300% increase or an increase of $25/MW of regulation above the reference level, whichever is lower
  * Time based offer parameters: an increase greater than 2 hours in elements of a generator's offer data that are expressed in time (e.g. minimum run time, minimum down time, cold start time, hot start time) or greater than six hours for any combination of such time-based offer data compared to the unit's reference levels
  * Offer parameters expressed other than in time or dollars: a 100% increase for offer data that are minimum values, or a 50 % decrease for offer data that are maximum values (including, but not limited to, ramp rates and maximum starts per day)

- Thresholds in constrained areas - ISO-NE uses the following thresholds for offers for both the day-ahead and in real-time markets when constraints are binding:-

  * Energy offer price; an increase of $25/MWh or 50%, whichever is lower, above the reference level
  * Start-up or no-load price; an increase of 50% above the reference level

3. An "impact test". Before imposing any mitigation measure ISO-NE investigates whether the offers and bids in question would, if not mitigated, cause a material effect on the LMP at a node, or in operating reserve charges. A material impact is defined as:-

- For the general market an increase of 200% or $100/MWh, whichever is lower, in the LMP and 200% or $25/MWh, whichever is lower, in any market. The general market impact is calculated by re-running the pricing software. The non-compliant generator offers of a pivotal supplier are replaced by offers at the reference level and prices are recalculated. This calculation is performed separately for each pivotal supplier at the portfolio level.

- The constrained area threshold is the tighter $25/MWh threshold. The market impact test is calculated as the difference between the congestion component of the LMP at the non-

[48] Where adequate information is available the reference level is set at the lower of the mean or the median of a generator's offers that have been accepted and are part of the seller's day ahead generation obligation or real time generation obligation (excluding negative values) or bid components in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing relevant fuel indices where appropriate. If data is not available, then the mean of the LMP at the generator's location during the lowest-priced 25 % of the hours that it was dispatched over the previous 90 days for similar hours or load levels, adjusted for changes in fuel prices. Finally if that is not feasible, ISO-NE will negotiate a level with the generator intended to reflect a unit's marginal cost.

compliant generator node and the LMP at the New England hub payments paid to generators that are dispatched out-of-merit to make them whole. Also ISO-NE investigates an increase of more than 100% due to the participant facing mitigation in a dispatch day, provided that the increase also exceeds $10/MWh compared to the operating reserve credits calculating using reference levels

Offers exceeding the conduct thresholds and market impact thresholds and for which no sufficient explanation has been provided are mitigated to the default, which is designed to cause a generator to offer its marginal cost as if it faced workable competition.

In its 2007 Assessment of the Electricity Markets in New England[49] the Independent Market Monitoring Unit first analysed supplier market shares, HHIs and pivotal supplier indices for both the whole market and for six sub markets:-

- All of Connecticut
- West Connecticut
- Southwest Connecticut
- Norwald-Stamford which is in Southwest Connecticut
- Boston
- Lower South East Massachusetts

The system was tight in southwest Connecticut, where generation resources and input capability only just equaled the summer peak load. Although the HHI for the whole market was only 525, that for Lower Southeast Massachusetts was 4700.

The Independent Market Monitoring Unit reported that “Based on our analyses in the competitive assessment section of the report, we found:-

- The largest suppliers in six of the seven areas are pivotal in a large number of hours

- However, when we account for the large amounts of nuclear capacity and the effects of reliability agreements, we find a pivotal supplier in: (i) Lower South East Massachusetts in 88 percent of hours, (ii) Boston in 25 percent of hours, and (iii) All of New England in 14 percent of hours

- Market power will be a more significant concern in Connecticut once the large quantity of reliability agreements begin to expire. Hence, it will be important to continue to monitor these areas and ensure that the market power mitigation measures are fully effective

[49] http://www.potomaceconomics.com/uploads/isone_reports/ISONE_2007_IMMU_Report_FINAL_6-30-08.pdf

We analyzed potential economic withholding (i.e., raising offer prices to reduce output and raise prices) and physical withholding (i.e., reducing the claimed capability of a resource or falsely taking a resource out of service):-

- Economic withholding was measured by estimating an output gap for units that fail a conduct test for their start-up, no-load, and incremental energy offer parameters indicating that they are submitting offers in excess of competitive levels. The output gap is the difference between the unit's capacity that is economic at the prevailing clearing price and the amount that is actually produced by the unit. In essence, the output gap shows the quantity of generation that is withheld from the market as a result of having submitted offers above competitive levels. Therefore, the output gap for any unit would generally equal:-

  $Q_i^{econ} – Q_i^{prod}$ when greater than zero, where:
  Q_i^{econ} = Economic level of output for unit i; and
  Q_i^{prod} = Actual production of unit i.

  To estimate Q_i^{econ} the economic level of output for a particular unit, it is necessary to evaluate all parts of the unit's three-part reference level: start-up cost reference, no-load cost reference, and incremental energy cost reference. These costs jointly determine whether a unit would have been economic at the clearing price for at least the unit's minimum run time.

  * Boston is a large net-importing region, making it particularly important to evaluate the conduct of its suppliers; the overall amount of output gap in Boston was modest, ranging from 1 to 3 percent of total capacity depending on load level

  * "the region-wide output gap was generally low for each of the four categories of supply, although some categories exhibited higher output gap quantities at higher load levels. Supplier A exhibited a small output gap under all load conditions. Supplier B exhibited a small output gap under all load conditions, although it was somewhat higher when load exceeded 23 GW. As a group, the other New England suppliers show higher derating levels under low load conditions, but derating levels decrease as load levels increase. These patterns generally suggest that New England suppliers have increased the availability of their resources under peak demand conditions rather than physically withholding resources"

"Based on the analyses of potential economic and physical withholding, we find that the markets performed competitively with little evidence of market power abuses or manipulation in 2007. The pivotal supplier analysis suggests that market power concerns exist in a number of areas in New England. However, the abuse of this market power is limited by the ISO-NE's market power mitigation measures and the large amount of capacity under reliability agreements".

"However, we find that frequent supplemental commitment has encouraged some generators to raise offers above competitive levels (i.e., above marginal cost). Generators committed for local reliability often do not face meaningful competition and may have local market power. The market power mitigation measures have generally limited the ability of suppliers to exercise market power. However, due to the chronic nature of some local reliability commitments, the mitigation measures have not been fully effective at addressing certain conduct. In particular, conduct by a large supplier in Boston resulted in substantial increases in Net Commitment Period Compensation ("NCPC") payments in 2007".

The Internal Market Monitoring Department developed a simple unconstrained model for conducting competitive benchmark analyses, using a similar approach to that developed by James Bushnell and Celeste Saravia of the University of California Energy Institute[50]. Actual prices are compared with the competitive benchmark, which is an estimate of the market-clearing price that would result if each market participant acted as a price taker and the market operated efficiently[51]. The benchmark price accounts for production costs (including environmental costs and variable O&M), unit availability, and net imports. It thus represents the estimated incremental costs associated with the least expensive unit that is not needed to serve demand in a given hour. Exhibit 4 compares the benchmark price estimate for 2007 with the actual energy clearing price and 2003, as well as the unconstrained bid-intercept prices for 2002 and 2003. The model results suggest that the market behaved competitively through 2007.

Exhibit 4 ISO model market price measures 2007

Price measure	2007 price ($/MWh)
benchmark price	63.5
energy clearing price	69.6
aggregate bid-intercept price	64.9

[50] James Bushnell and Celeste Saravia, An Empirical Analysis of the Competitiveness of the New England Electricity Market, University of California Energy Institute, May 2002. The study report can be found at http://www.ucei.berkeley.edu/PDF/csemwp101.pdf.

[51] The metric used to compare these market price measures is the Quantity-Weighted Lerner Index ("QWLI"). The conventional Lerner index, defined as the price-cost margin in percentage terms (Lerner Index = (P-MC)/P, where: P = price and MC = cost of marginal resource) is widely used to assess the competitiveness of market outcomes. The QWLI weights each hour's Lerner index by total system-wide load, which provides a more appropriate metric than a simple arithmetic average of the hourly Lerner Index. For mergers and acquisitions analysis in the US Department of Justice FERC divided market concentration measured by HHI into three that can be broadly characterized as unconcentrated (HHI below 1000), moderately concentrated (HHI between 1000 and 1800), and highly concentrated (HHI above 1800). Although the resulting classifications provide a framework for market concentration analysis, they are imprecise. A low concentration index does not guarantee that a market is competitive, higher values are indicative of greater potential for the exercise of market power by participants.

7.3.2.1 The ISO-NE reliability option market

ISO-NE has implemented a new form of capacity market called the "Forward Capacity Market" [52], which also mitigates market power. ISO-NE buys a product which provides a payment for capacity, but the design of the product is not the traditional simple capacity ticket but a reliability option[53] (RO). An RO is a call option that is both physical and financial. It is physical in that it is associated with a specific plant and represents a physical call option on the amount of energy produced by one MW of generating capacity from that plant. It requires a plant to be generating or to be supplying reserves (i.e. to be available to generate) when the system is stressed. It is financial in that it is a one way contract for difference with a strike price that is set about 15% above the highest marginal cost unit[54]. If the system is under stress and the spot price rises above the strike price then the generator has to pay the difference to ISO-NE. This payment has two consequences. First, it gives the generator a clear incentive to be generating when the price is high in order to make the money to offset the payment. And second, to the extent that it is contracted, the payment eliminates the incentive for the generator to price high because the generator has to pay the difference between price offer and strike price to ISO-NE. Importantly, the adjustment takes place immediately and automatically in the daily settlement process. *Plants that sell ROs are swapping the revenues that they would have received in a pure energy market from selling electricity into price spikes at times of scarcity for an assured steady income.*

Each year ISO-NE determines how many MWs of installed capacity the system will require in 3 or 4 years in the future, and then holds a descending-clock auction[55] for this number of ROs. The options will go into effect for 1 year for existing units and up to 4 years for newly built units starting 3½ years

[52] The principles of the ISO-NE "Forward Capacity Market" were approved by FERC in June 2006, and the rules were "summarized" in a cover letter (of 204 pages) on 15 February 2007 by ISO-NE to FERC, and now have been approved by FERC.

[53] "Reliability Options: A Market-Oriented Approach to Long-Term Adequacy", Miles Bidwell, *The Electricity Journal*, Vol 18, Issue 5, June 2005

[54] The strike price is set at a heat rate of 22,000 BTU/kWh * gas price. With current gas prices of $8/MMBTU, the strike price is about $200/MWh.

[55] A descending-clock auction starts with a price that is sufficiently high to induce offers that total more than the capacity required by ISO-NE. The auctioneer then announces sequentially lower prices and at each price participants for whom the new price is too low withdraw from the auction. The auctioneer continues to announce sequentially lower prices until the supply of ROs equals the capacity required. At this point the auction stops and this price determines the cost of new entry until the next auction. The process is described in a report by the National Economic Research Associates prepared for PJM, NYISO, and ISO-NE in 2003. The NERA report is available on www.pjm.com /go to Committees & Groups/go to Working Groups/go to resource Adequacy Model/NERA's Final Report on Centralized Resource Adequacy Markets, February, 2003.

after the auction, at which time the winning generators will be paid for the ROs that they have sold to ISO-NE. Thus, a prospective generator that wishes to build a 150 MW plant, can offer to sell up to 150 ROs to ISO-NE. These ROs will be associated with this plant and the plant will be penalized if it is either not generating nor is not available as a reserve when the option is called at a time of system stress.

Unlike most market power mitigation mechanisms, ROs eliminate market power without distorting the spot energy market, adversely affecting other financial instruments, or harming generators. Structuring a market so that marker power abuse will be unprofitable is generally considered to be a better approach than imposing threats of punishment and non-market mechanisms on markets whose structure allows the profitable exercise of market power. While the first auction in February 2007 was adjudged a success with competitive offers of 6GW of potential new resources offering from which 1.8GW was selected, since the products from it are not activated until June 2010 it is not possible to comment on their effectiveness in mitigating market power.

7.3.3 Market power mitigation in PJM

The PJM market evolved from the cooperative power pool that included the electric companies in Pennsylvania, New Jersey, Maryland, Delaware, Washington DC, and Northern Virginia. It has subsequently more than doubled in size both in terms of capacity and load, and geographical area to include a region with 51m people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

The "PJM Market Monitoring Plan" creates a Market Monitoring Unit that is responsible for implementing the Plan, and is now separate from the PJM[56]. The Market Monitoring Unit is empowered to request a Market Participant to discontinue actions that it considers violates the Tariff; to make recommendations to PJM Committees and the PJM Board; and reports to FERC.

Apart from the energy price cap of $1000/MWh in the day-ahead and real time energy markets, and in the regulation market, PJM does not have an "algorithmic" approach to *general* market power

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[56] Originally the MMU was part of PJM, but in 2007 there was a dispute between it and the chief executive that was one of several factors leading to the Board of PJM asking him to take early retirement and clear his desk. The MMU was reconstituted as an independent company Monitoring Analytics.

mitigation. The focus of the PJM mitigation effort is on load pockets, where the approach is algorithmic. There is automatic mitigation of bids from generating units dispatched for congestion relief unless a structural screen (the three jointly pivotal supplier test) is passed on a day-ahead and real-time basis. If the incremental output of the three largest suppliers in a load pocket is removed and enough generation remains available to meet the incremental demand for constraint relief at a price of less than, or equal, to 1.5 times the general market clearing price, then there is no capping. When offer caps are enforced, offer-capped units receive the higher of the general market price or their offer cap, which is marginal cost plus 10%.

The 2007 state of the Market report by the Market Monitoring Unit[57] (MMU) is a massive study of more than 495 pages. Regarding the competitiveness of the energy market:-

- Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments as measured by the HHI

	Minimum	Average	Maximum
Base	1,239	1,392	1,603
Intermediate	664	2,158	6,365
Peak	596	3,746	10,000

- The load-weighted, unit markup index. The markup index for each marginal unit is calculated as (Price – Cost)/Price. The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost. This index calculation method weights the impact of individual unit markups using sensitivity factors. In 2007, the annual average markup index was 0.09 with a maximum of 0.22 in June and a minimum of 0.03 in January. The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs, which is strong evidence of competitive behaviour

- 57 hours of high load occurred in 2007. Within these hours, there were three hours on August 8 that met the criteria for potential within-hour scarcity (which is related to the system operator taking emergency actions such as buying in emergency power) and PJM triggered its scarcity pricing when all offer caps are suspended

- Offer capping is an effective means of addressing local market power, but levels have been low. In the day-ahead energy market offer-capped unit hours fell from 0.4% in 2006 to 0.2% in 2007. In the real-time energy market offer-capped unit hours rose from 1.0% in 2006 to 1.1% in 2007

- Since PJM consolidated its regulation markets into a single combined market, the MMU has consistently found that it is characterized by structural market power. Based on the MMU analysis of the relationship between the offer prices and marginal costs of units that set the price in the

57 http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/NYISO_2007_SOM_Final.pdf.

> regulation market, the MMU cannot conclude that the regulation market produced competitive results or noncompetitive results. *The MMU recommends that all suppliers be required to provide cost-based regulation offers as part of real-time market power mitigation*

The report analyses the net revenue received by generators, and concludes that the combination of revenues from the energy markets, the ancillary services markets, and the new Reliability Pricing Market for capacity (which generated $4bn p.a.) has been sufficient to stimulate $5bn investment in upgrading.

7.3.4 Market power mitigation in the ERCOT market in Texas

FERC has no jurisdiction over the Electricity Reliability Council of Texas (ERCOT) interconnected system in Texas (which supplies about 85% of the load in the state) because it is not AC interconnected with other states and so is not subject to the provisions of interstate trade which under the Federal Power Act gives FERC its powers. The ERCOT system produces about 375TWh p.a. and serves 7.3m customers.

While the market will be changed to a Standard Market Design in 2009, currently it is zonally based; there is a real time balancing market but no day-ahead market; and it is an energy only market. The Public Utility Commission of Texas (PUCT) is the regulatory authority for both the wholesale and retail markets. PUCT has close links with the legislature, and every other year while the legislature sits it publishes a review of the market, and if deemed necessary asks for additional regulatory powers. It has powers to monitor, and recommend on, the exercise of market power.

Engaging in market power abuse is a violation of the Public Utility Regulatory Act (PURA) 39.157(a), which states in part:-

> For purposes of this subchapter, market power abuses are practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition…For purposes of this section, "market power abuses" include predatory pricing, withholding of production, precluding entry, and collusion.

and also the Act requires the PUCT to monitor market power associated with the generation, transmission, distribution, and sale of electricity in the State of Texas:-

> On a finding that market power abuses or other violations of this section are occurring, the commission shall require reasonable mitigation of the market power by ordering the construction of additional transmission or distribution facilities, by seeking an injunction or

> civil penalties as necessary to eliminate or to remedy the market power abuse or violation as authorized by Chapter 15, by imposing an administrative penalty as authorized by Chapter 15, or by suspending, revoking, or amending a certificate of registration as authorized by Section 39.356. Section 15.024© does not apply to an administrative penalty imposed under this section.

The possession of market power is not, however, in and of itself, a violation of PURA. Rather, PURA prohibits *actions* by a person with market power that tend to unreasonably restrict, impair, or reduce competition, and should the Commission determine that such abuse has occurred, then mitigation of the market power is required.

P.U.C. SUBST. R. 25.503(g)(7) states:-

> A market participant shall not engage in market power abuse. Withholding of production, whether economic withholding or physical withholding, by a market participant who has market power, constitutes an abuse of market power.

Upon finding that market power abuses are occurring, the Commission is mandated to require reasonable mitigation of the market power by either:-

- Requiring the construction of additional transmission or distribution facilities
- Seeking an injunction or civil penalties as necessary to eliminate or remedy the market power abuse
- Imposing an administrative penalty as authorized by Chapter 15 of PURA
- Suspending, revoking, or amending a certificate or registration

There are two concerns about market power in ERCOT. First load pockets, which are of concern in both Houston, where NRG owns about 60% of the plant, and in Dallas/Fort Worth, where TXU is the dominant generator and owns 44% of the capacity and there is a significant shortfall of power compared with demand. Second, the general concern about general market power because TXU power generation companies own and operate the largest power generation fleet in the ERCOT market with 18GW of generation, which represents 22% of all generation ERCOT-wide.

In a 2004 report by the Market Oversight Division, Staff found that:[58]

> "… TXU has a position in the ERCOT market strong enough to affect the balancing energy MCPE consistently. Indeed, the results of this study show that TXU's market position is so

[58] Public utility Commission of Texas, "Staff Inquiry into Allegations Made by Texas Commercial Energy regarding ERCOT Market Manipulation," Austin, Texas, January 28, 2004.

> pivotal that just about anything the company does with respect to the balancing energy stack will affect balancing energy prices, regardless of the reasons behind its decisions".

In the 2005 State of the Market Report for the ERCOT Wholesale Electricity Markets[59] prepared by Potomac Economics, the Independent Market Monitor, contained several analyses related to the conduct of market participants in 2005, namely the possibility that certain market participants may have engaged in physical or economic withholding of generation from the market. In 2006 the consultant found that TXU was able to set the wholesale price about 75% of the time in 2005, and concluded that TXU might have manipulated the market by withholding 10% of its generation when demand peaked. In March 2007 Potomac Economics completed a report which concluded that during the period from 1 June to 30 September 2005 for the hours 10 through 23, TXU had market power because its energy offers were necessary to satisfy the demand and engaged in behaviour that constituted market power abuse by economically withholding production from its generation units and offering its energy into the market at prices well in excess of its marginal cost. The report concluded:-

- TXU's behaviour raised prices in the balancing energy market by an estimated 15.5% during the study period
- TXU profited from that abuse during the study period by an amount of approximately $19.6m
- TXU increased the costs of the balancing energy market by approximately $70m during the study period

Commission staff recommended that TXU be required to pay $210m, consisting of administrative penalties in the amount of $140m and refunds of $70m, a figure that is three times the level of damage inflicted upon the ERCOT balancing energy market by TXU's actions, see Annex 3. The award of treble damages is a long-standing remedy in antitrust law. A multiple of three is approximate in this instance to account for the harm to the ERCOT wholesale and retail markets caused by TXU's actions in the balancing energy market. Of this total amount, TXU be required to refund $70m, plus interest, to ERCOT, for resettlement to other market participants that were damaged by TXU's actions, and that the remaining portion of the $210m, approximately $140m, be paid to the Comptroller as administrative penalties. Alternatively, the entire $210m should be paid to the Comptroller as administrative penalties. The PUCT filed in court, and negotiations are in process to reach a settlement.

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[59] http://www.potomaceconomics.com/uploads/ercot_reports/2005%20ERCOT%20SOM%20REPORT_Final.pdf.

8. EXPERIENCES WITH MITIGATING MARKET POWER

The foregoing case studies point out that market power and its abuse are of major concern to regulators and legislators, and even where there is no apparent exercise of market power, the very fact that it can be exercised is sufficient for the implementation of rules to minimise its potential impact. The case studies show that there are two broad approaches to mitigating market power:-

- *Ex ante* mitigation with restrictions on the behaviour of firms, such as price caps, bidding restrictions, or mandated prices that reflect anticipated costs which does not rely on extensive fact finding, analysis and prosecution

- *Ex post* enforcement, which focuses on identifying after-the-fact instances of anti-competitive conduct (e.g. evidence of collusion, significant output withholding or other inefficient behaviour) and punishing the behaviour (*e.g.,* fines, damages payments, etc.)

Even though that rulemaking has not directly led to an order, FERC's strong preference for *ex ante* mitigation procedures is evident in the fact that all FERC-regulated RTO markets rely on *ex ante* mitigation processes, and is exemplified by the US North East markets, which are characterized (as is the National Electricity Market) by a formal and transparent compulsory stacking energy market (i.e. a gross pool), which allows easy identification of who is doing what. As noted in 7.2 FERC does not have powers to restructure the electric industry it relies more on ex-ante mitigation rather than allowing events to occur, and subsequently analyzing them. Although the Alberta market is similar, ex ante mitigation is not used, while BETTA (and other continental European markets except for Spain) is a "net" market where generators self dispatch and their pricing behaviour in the *main energy market* is not particularly transparent and so they are not amenable to ex-ante mitigation but rely on ex-post mitigation[60].

The case for *ex post* mitigation is that, while *ex ante* mitigation can be comparatively quick and formulaic, it risks being too prescriptive, overly broad, and having unintended consequences, notably the implementation of mitigation actions when market power abuse does not exist. Thus, *ex ante* rules may impose costs that exceed their corresponding benefits if they force market participants to alter their behavior under conditions where the market is performing efficiently. By contrast, *ex post* mitigation can be less formulaic and more specifically tailored to those instances in which a market participant is demonstrated to have engaged in anticompetitive or otherwise inefficient behavior.

[60] The pricing behaviour of generators in the balancing mechanism and for resolving constraints is, however, transparent to the system operator (National Grid) which has an incentive scheme to reduce these costs and consequently a commercial incentive to reduce market power.

The case for *ex ante* mitigation is that it is more transparent and reduces regulatory risk compared to sole reliance on *ex post* enforcement. In addition, *ex ante* mitigation avoids the often slow, potentially costly, uncertain, and burdensome investigations associated with *ex post* enforcement regimes. The *ex ante* mitigation processes start with a price cap and are supplemented by either "structural" or "conduct-and-impact" approaches or both. A report for PJM[61] comments:-

- "The *structural approach* to mitigation is based on using structural tests such as the HHI and the pivotal supplier test to identify conditions under which the exercise of market power is likely. The structural tests do not measure market power, but indicate when it is more rather than less likely to occur and can be used as a screen to trigger ex-ante mitigation. Structural tests are used for two major purposes: (1) to determine whether to impose offer caps, and (2) as a screen to determine whether to subject particular suppliers to further tests…A disadvantage of structural approaches is the difficulty of devising structural screens and thresholds that: (i) are applied to correctly-defined relevant product and geographic markets, which may not be a trivial task; and, (ii) are able to accurately identify the likely exercise and abuse of unilateral and multilateral market power within these relevant markets. Consequently, while the choice and specific implementation of a structural screen might appear to be relatively simple, there are significant uncertainties about the ultimate reliability of the mitigation process as it can result in both under- and over-mitigation[62]"

- "The *conduct-and-impact approach*[63] to analyzing market power is to directly assess a generators' conduct and its impact on market prices, such as offering above cost or engaging in physical and economic withholding of output and to trigger mitigation if offers and their market impacts exceed certain pricing thresholds. They are applied *after* bids are submitted, but bids are then mitigated to appropriate reference levels *before* the "official" market-clearing price is determined. NYISO and ISO-NE adopt this approach for both the general market and for load pockets, while PJM adopts it for load pockets". This approach requires that competitive reference levels are specified which are supposed to approximate offers under workably competitive conditions and are generally used as a substitute for an entity's original offer if a structural or conduct-and-impact test is failed. The reference levels can be grouped into four main categories:-

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[61] Review of PJM's market power mitigation practices in comparison to other organized electricity markets, The Brattle Group, 14 September 2007, http://www.brattle.com/_documents/UploadLibrary/Upload631.pdf.

[62] The consequences of over-mitigation has been recognized by FERC:-

> Over-mitigation would mean that generators will not be able to recover all of the costs that they should, and generators may exit the market, or be less likely to enter. Even the threat of over-mitigation may keep market participants out of the market. Fewer competitors can mean less system flexibility and thus ultimately less reliability, and for this reason it is also appropriate to avoid over-mitigation.

Federal Energy Regulatory Commission (2004c). Order on Rehearing [Addressing MISO's Tariff Proposal], Docket No. ER04-691.

[63] The conduct tests consist of comparing a supply bid to a pre-defined threshold (*e.g.*, 300 percent above the reference price). The impact tests, which are performed only where the conduct tests fail, detect whether the specific bids in question increase prices or out-of-market uplift payments above pre-defined thresholds relative to reference-level bids. Conduct-and-impact thresholds typically apply uniformly to all supply resources in the entire RTO. However, all three RTOs utilize more stringent conduct-and-impact thresholds that apply to localized geographic markets that are presumed to be more prone to noncompetitive outcomes due to transmission limitations.

* *offer-based reference levels* which are generally based on average offers bids from the unit that were accepted in competitive periods. This approach is the first choice for calculating reference levels in the NYISO and ISO-NE

* *LMP-based reference levels* which are generally based on the average LMP for the unit during low priced periods (e.g. the lowest price 25% of hours over the previous 90 days)

* *cost-based reference levels* which generally reflect a unit's incremental operating costs. Such levels may be based on a measured cost that is indexed, or may be negotiated

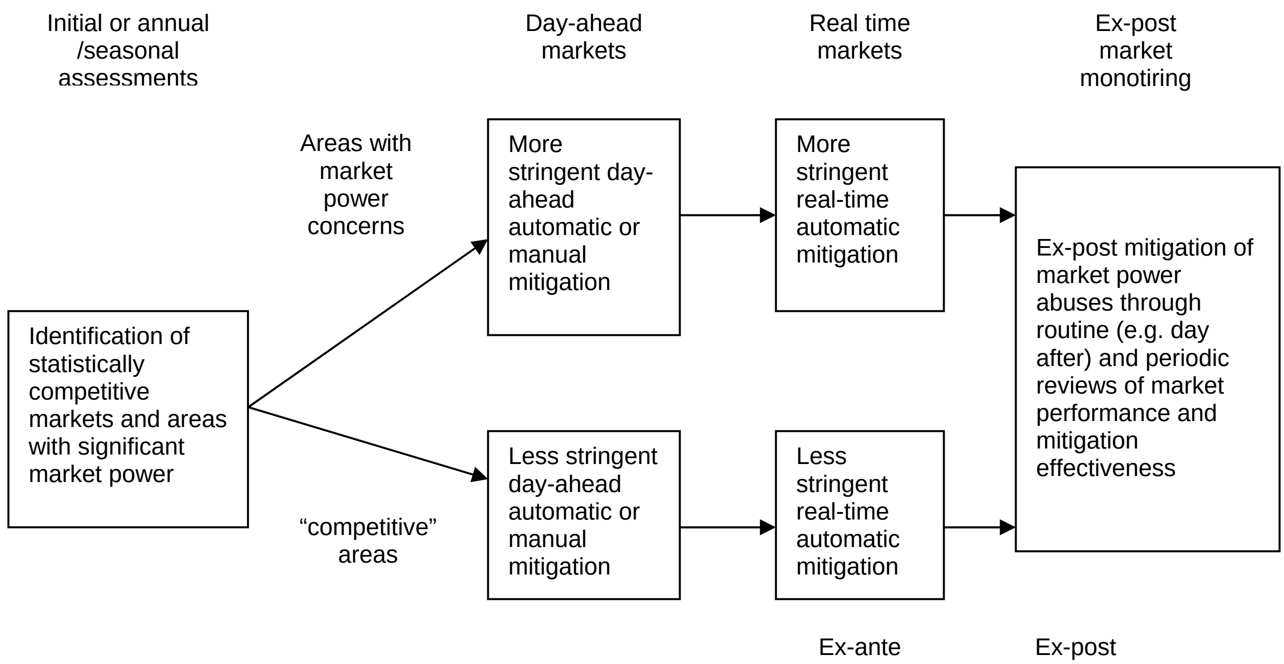
* *frequently mitigated unit options*: a cost-based adder for units that are frequently mitigated more than 80% of their operating hours over a given year. PJM allows an adder of $40/MWh over cost

“The advantages of mitigation protocols triggered by conduct-and-impact tests are that, if designed properly, they identify and mitigate only substantial or unreasonable exercises of market power based on an explicit choice of bid and market impact thresholds. This reduces the risk (and perception) of over-mitigation. The use of simple bid and price impact thresholds also generally results in a mitigation process that is relatively transparent to market participants. Finally, threshold-based conduct-and-impact approaches readily accommodate after-the-fact analysis of the extent to which firm conduct is deviating from some competitive norm, particularly if mitigation is triggered when an individual participant deviates significantly from either past behavior (during a competitive benchmark period) or a designated cost-based standard. The disadvantages of conduct-and-impact-based mitigation are that the chosen bid and price thresholds used in a mitigation processes may either be too low (resulting in excessive mitigation) or too high (resulting in the failure to detect abuses of market power below threshold levels).

PJM and ERCOT use structural screens, whereas NYISO and ISO-NE rely primarily on conduct-and-impact tests. Through the manner in which these screens are applied, it appears that the former set of RTOs may place more emphasis on avoiding false negatives (i.e. a relatively more “stringent” approach from the perspective of the market participants being examined) in their market power mitigation approach, whereas the latter set of RTOs places more emphasis on avoiding false positives (i.e. a less stringent approach from the perspective of the market participants being examined). “Based on our review of the strengths and weaknesses of both approaches, we find that a more integrated structure, conduct, and performance framework is advisable for triggering market power mitigation measures…In other words, we find that these two approaches, structural and conduct-and-impact, do not need to be substitutes for one another. Rather, they are naturally complementary.

Purely structural screens can benefit from an added conduct-and-impact assessment that avoids mitigation actions if market behavior does not suggest that significant market power is being exercised. Similarly, a conduct-and-impact screen can benefit from the inclusion of an additional structural screen that can identify market conditions or geographic regions where significant market power concerns exist.

Exhibit 5 Sequence of market power mitigation procedures



Source: Brattle, see footnote 61.

The implementation of automatic *ex ante* mitigation in US organized electricity markets coupled with *ex post* monitoring and enforcement capability differs significantly from the almost sole reliance on *ex post* mitigation regimes used in most other markets, including the electricity markets in Britain and Alberta. The combination of *ex ante* and *ex post* mitigation is a significantly more stringent enforcement regime than the approaches adopted in Alberta and Britain.

9. CONCLUSIONS

It is clear that the risk of exercise of generator market power has been identified and addressed in considerable detail in these jurisdictions. Regulators and legislators have recognised that the electricity market is particularly susceptible to the exercise of generator market power. FERC has taken the view that it is not possible in an energy only market to differentiate between the scarcity pricing needed to remunerate capacity in an energy only market and the exercise of market power. It has consequently supported an ex-ante approach that mitigates offers to the energy market to more or less system marginal costs and complements the revenue from the energy markets with a capacity market (which also assures generation adequacy). This approach is adopted in the three North Eastern markets of New York, New England, and PJM. The authorities responsible for the other three markets – Britain, Alberta, and Texas, which are all energy only markets – have adopted an ex-post approach. The British authorities have tried restructuring the market (which achieved nothing) and divestment as a remedy to market power, which worked for a while until the authorities allowed the electric industry to consolidate and vertically integrate; now the problem may have emerged again. Alberta has resolved a couple of issues by the regulator getting changes made to market arrangements. The Texas regulator is trying to discourage the exercise of market power by imposing a fine representing triple the amount that market revenues increased resulting from the abuse of market power.

Without a doubt the US approaches – whether in the ex-ante mitigation in the FERC markets or the attempt by the Texas regulator to impose a very large fine for market power abuse – are much tougher than the approaches adopted in Alberta and Britain. And all of the jurisdictions have much more forceful means of market power mitigation than the NEM.

Annex 1 The way of the market in England & Wales then Britain and Ofgem's response

A.1 The early days

Due to the government's misguided and failed attempt to privatize the nuclear plants by creating an enormous generator that would supposedly be large enough to absorb the various risks of nuclear plants, the electric generation industry in England & Wales was created in 1990 as two very large thermal generators – National Power with 29GW of plant, and PowerGen with 19GW of plant – Nuclear Electric with 10GW of plant, and about 3GW of other plant. National Power and PowerGen set the marginal price.

By the end of 1993 the regulator had prepared 5 reports on the behaviour of the two largest generators, National Power and Power Gen, all of which concluded that the dominant generating companies were exercising market power. In 1995 he used the threat of a referral to the Competition Commission to induce National Power and PowerGen to divest of respectively 4,000MW and 2,000MW of generation, and also imposed an annual average price cap during 1995 and 1996. The disposal was poorly conceived, because not only was all of the plant sold to the same purchaser, the Eastern Group, but also the plants were sold with an "earn-out" that required the purchaser to pay £6/MWh when it generated. The effect of this was to ensure that Eastern would not run the plant base load, but would operate mid-merit. It "joined the club", and priced the plant more aggressively than National Power and PowerGen had – consequently the divestment did not achieve what the regulator hoped for.

The Labour government elected in June 1997 was concerned about high electricity prices. Its first move was to ask the regulator to review the Pool, which the government considered facilitated the exercise of market power, and this led in due course to the introduction of the New Electricity Trading Arrangements (NETA) in March 2001, which in April 2005 was extended to Scotland and renamed the British Electricity Trading and Transmission Arrangements, BETTA. In reality, while the Pool had flaws of governance[64] and the capacity payment was clearly manipulable[65], the basic problem was

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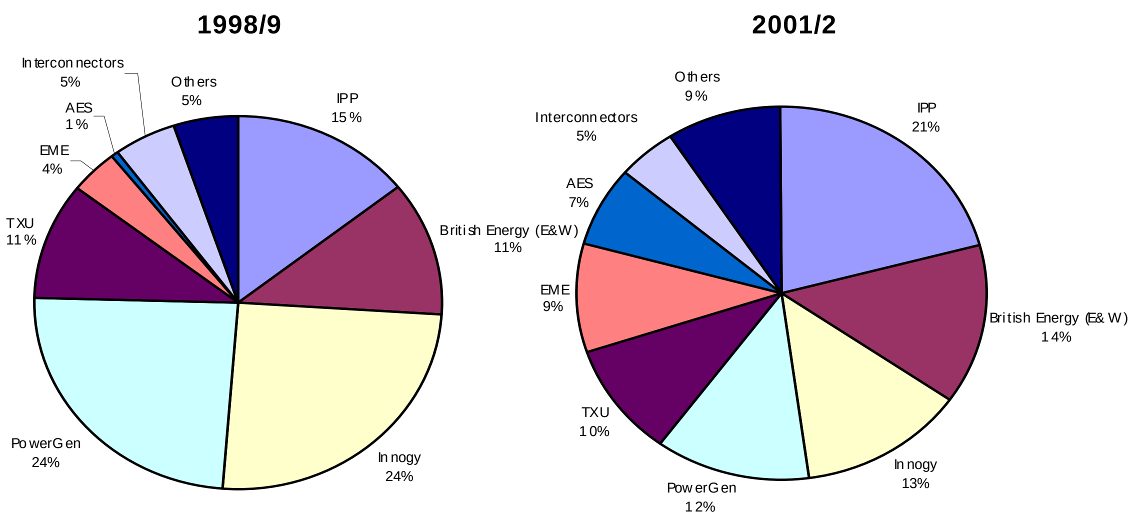
[64] In order to give comfort to investors at the flotation of the industry the governance structure was designed 1) to reduce regulatory risk by limiting the ability of the regulator to make changes to the Pool Rules, and 2) to ensure it would be difficult for either generators in concert or retailers in concert to make changes that would benefit their interests at the expense of the other group.

[65] There were three components to the price which consuming parties paid to take electricity from the Pool:-

1. The system marginal price, which was based on offers to generate made for individual units
2. A capacity payment, which was based on an administratively set value of lost load times and calculated probability of loss of load.
3. Uplift, which included the costs of ancillary services, constraints, and forecast errors.

not the Pool but the concentration of ownership. The change to NETA was politicized, and the government and Ofgem spun claims that its introduction had a significant effect in reducing prices. But closer and cooler examination showed these claims were baseless; prices reduced because of the fragmentation of ownership of plant, see exhibit 6.

Exhibit 6 The major change in shares of the generation market between 1998/99 and 2001/02



In 1998 a new, and more interventionist, regulator was appointed. In February and October 1999 there were further reports on Pool prices, and he commenced his attempt to introduce the Market Abuse Licence Clause. National Power and PowerGen saw that with the growing political concern about their market power, and with the significant increase in completion of merchant combined cycle gas turbine plant, the old game was coming to an end. Without too much pressure they both agreed to sell 2GW more plant, and as a quid pro quo they were now allowed to buy Regional Electricity Companies – the owners of distribution networks and of retailing businesses - which was the beginning of a rapid move to vertical integration. In fact they divested 13GW of plant, and both reduced their plant portfolio to about 8GW. National Power surprised the market by offering its best coal plant, the 6 x 660MW Drax coal plant for sale, and it was bought by the US firm AES. National Power also divested its portfolio of international plant to International Power, renamed itself Innogy and bought the retailing business of three Regional Electricity Companies, before in turn being bought by the German company RWE. Edison Mission bought 4GW of coal plant from PowerGen for £1.3bn, which also sold a 2GW coal plant to London Electricity. PowerGen bought a Regional

Electricity Company and the retailing businesses of two others, before itself being bought by the German company E.On.

Between 1998/99 and 2001/02 concentration of ownership of generation fragmented as shown in exhibit 1; the Herfindahl-Herschman Index[66] (HHI) reduced from 2200 in 1998 to 1170 in 1999-00, and reduced further to 670 in early 2001.

Also over the period 1999-2002 retailing consolidated into six major retailers - E.On, EDF Energy, RWE-Innogy, Scottish Power, Scottish and Southern Energy, and Centrica (British Gas) - between them they supply 99% of the residential customers and 70% of the commercial and industrial customers. The first five of the companies are broadly vertically integrated, with their generation covering at least their residential load, while Centrica is short generation.

A.2 The second period - prices plummet

A detailed examination of day ahead and month ahead prices showed that at the beginning of 2000 Innogy, PowerGen and TXU Europe began to lose control of prices and the price of wholesale power tumbled, see exhibit 1. One factor depressing prices was that it was a warm winter. Another was that Edison Mission and British Energy doubled the outputs of the plants they had bought as compared with how National Power and PowerGen had run them. Furthermore it is widely believed that a large trader shorted the market in early 2000, and one or two other traders may have joined in. In March 2000 TXU Europe announced that it was temporarily withdrawing 2GW of plant (it returned 500MW of plant in June and the rest in October), and Edison Mission announced that it was temporarily withdrawing a 500MW unit from service because “market prices were too low”.

In October TXU Europe and Edison Mission returned their plants to operation, then over the winter 2000/01 several new CCGT plant started serious operation, and London Electricity (now EDF Energy) significantly increased the output of the plant it had bought compared with minimal production by PowerGen. Competition broke out in the generation market in the autumn of 2000, and prices dropped.

[66] The HHI is calculated by taking the market share of each participant as a percentage, squaring it and summing each number to give the index. Thus a monopolist with a 100% share of the market will have a HHI of 10,000, while if there are 10 companies, each with an equal share of 10%, the HHI = 10 x 10 x 10 = 1000. Normally such a low HHI would indicate a very competitive market

In 2002 and 2003 the price reductions had savage financial consequences for the non-integrated generators[67] in the market:-

- Edison Mission sold the 4GW plant it had recently bought to American Electric Power for £650m. In early 2003 American Electric Power halved the book value of the plant it had bought in, and subsequently sold it for £250m to Scottish and Southern Electricity

- TXU Europe went into administration because of the over-market contract which it had agreed with AES for part of the output of Drax. This then pushed Drax into financial distress, and AES walked away from it and another plant which it owned, leaving them with the banks

- British Energy, the generator which owned 10GW of nuclear power plants and a 2GW coal station, would have gone into insolvency, but was rescued by the government. In its 2002 accounts it wrote down the value of its British power stations by £3.74bn to £660m, and announced a pre-tax loss of £4.29bn

- About 2GW of project financed plant either went into administration or was repossessed by the banks

A.3 The third period - prices rise

Prices were pushed sharply up in the summer of 2003 by the very hot weather resulting in high demand, and also generation difficulties in France because the rivers were low which led to limitations on the operation of EDF's nuclear power plants; this resulted in the interconnector with France unusually transmitting power from England to France. Also generators were learning to "play the game" by withdrawing plant. The prospect of a low reserve margin over the winter 2003-04 led to National Grid expressing public concern about generation adequacy.

A.4 The fourth period – post 2005 prices rise and fall and rise

Prices increased in 2005 as a consequence of increases in gas prices, and also due to the introduction of the European Emissions Trading Scheme for CO_2 because the EU Allowances increased the marginal cost of generation from CCGTs – which are normally at the margin in Britain – by about £10/MWh. Then gas prices reduced and in 2006 the price of CO_2 allowances dropped to zero and electricity prices reduced, but in 2007 gas prices and hence electricity prices increased.

A report by the European Commission[68] estimated market concentration measured on an hourly basis over the 2003-2005 period and concluded that the two largest generators in Britain accounted for

[67] The integrated generators maintained prices to residential and small business customers.

about 32% of the total available installed capacity; and the HHI for the market was about 1,070. In addition, the report showed that only in very few hours (1 hour in 2004 and 6 hours in 2005) was any one large company pivotal in the overall market. The report concluded that the wholesale generation market in Britain was relatively unconcentrated and relatively competitive.

Although Ofgem claimed that the market was functioning competitively, the consumer body Energywatch (whose chief executive Allan Asher was formerly the Deputy Chairman of the Australian Competition and Consumer Commission) proclaimed loudly and often that the markets for residential customers and small businesses were not competitive and that the wholesale market was neither liquid nor transparent and was probably manipulated by the dominant 5 more or less vertically integrated large companies. In early 2008 four of the Big Six energy companies raised their electricity prices to residential customers by between 8% and 15%, which led to a sustained period of political lobbying to the government to take action about increased fuel prices and to introduce a windfall tax on energy companies. On 5 February 2008 the House of Commons Committee on Business and Enterprise announced an inquiry into "Energy prices, fuel poverty and Ofgem", and shortly afterwards Ofgem changed its tune and announced that it was undertaking a "probe" of the gas and electricity markets using its powers under the Enterprise Act.

The Committee published its report on 28 July 2008. It was concerned about the energy markets and was very critical of Ofgem, concluding[69]:-

> We have concerns that the UK's energy markets are not functioning as efficiently as they should, and that UK prices may be higher than those in competitor countries. We are concerned that Ofgem's terms of reference suggest it may pay relatively little attention to the wholesale markets, and, in particular, the wholesale gas market. Our overall conclusion on the functioning of both the gas and electricity wholesale markets is that there are significant questions that need to be addressed in the interests of both retail and business consumers. The price of gas determines the wholesale price of electricity, because gas-fired power accounts for around a third of the UK's generating capacity, and tends to provide the marginal source of generation to the market. We consider that the competitiveness of the wholesale gas market affects the competitiveness of the UK's energy markets as a whole, and deserves particular scrutiny. We have also identified important issues that need to be addressed in the retail market itself. We have, however, recommended consideration of the merits of referring only two aspects of the markets to the Competition Commission at this stage (the forward gas

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[68] The Preliminary Report is available on the DG Competition website at http://ec.europa.eu/comm/competition/antitrust/others/sector_inquiries/energy/#16022006

[69] http://www.publications.parliament.uk/pa/cm200708/cmselect/cmberr/293/293i.pdf.

market and the supply of electricity to the SME sector), and then only if Ofgem is unable to take sufficiently robust steps itself.

Ofgem published its investigation into the retail market on 6 October 2008 and will in due course publish an investigation into the wholesale markets[70].

[70] http://www.ofgem.gov.uk/Markets/RetMkts/ensuppro/Documents1/Energy%20Supply%20Probe%20-%20Initial%20Findings%20Report.pdf.

Annex 2 Alberta - **Draft of Fair, Efficient and Open Competition Regulation**

Alberta ENERGY

Electricity and Alternative Energy
Wholesale Policy

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Telephone 780/422-6061
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File No. 08-00055-07 ELEC

October 17, 2008

To: *Electric Utilities Act* Advisory Committee Members and Interested Parties

Re: Draft Fair, Efficient and Open Competition Regulation

The Government's vision for Alberta's electricity market requires that all market participants "conduct themselves in a manner that supports the fair, efficient and openly competitive operation of the market" (FEOC), as per Section 6 of the *Electric Utilities Act* (EUA).

Starting in late 2006, the Electricity Division of the Alberta Department of Energy (the Department) began working with stakeholders to further clarify Section 6 of the EUA and add a greater level of market certainty by putting in place a well defined structure for market participants and agencies to address FEOC issues.

In January 2008, the Minister of Energy, the Honourable Mel Knight, issued a Policy Letter laying out his policy recommendations regarding FEOC, and directed the Department to continue working with stakeholders to "provide the basis for regulation, rule and guideline drafting and development." The Department released a discussion paper (the "White Paper") on January 8, 2008, requesting stakeholder input on additional details for implementation of the Policy Letter. On July 31, 2008, the Department released a second discussion paper (the "Supplemental White Paper") requesting further stakeholder comments and input on particular details for implementation of the Policy Letter.

Throughout this process, stakeholders have provided important input, comments and suggestions on the concepts and requirements regarding Section 6 of the EUA and the methods needed to have more clarity and certainty for all stakeholders within Alberta's wholesale energy-only electricity market. This has assisted the Department in developing the attached draft FEOC regulation. A brief overview of specific areas of the draft FEOC Regulation follows.

Principles of Participant Conduct
The draft regulation is not written in a form that assumes the existence of market power, nor the abuse of market power. Instead, the original principles for Section 6 have been used to guide the development of conduct that does not support FEOC.

Serious consideration was given to including a 'legitimate business purpose' defence for conduct that may be inconsistent with FEOC. The Department chose not to include a 'legitimate business purpose' defence based in part on its view that the regulation should not define nor preclude whatever the market participant feels would be an appropriate defence for conduct that has been identified in the regulation as not supporting FEOC.

Information Sharing
The Department agrees with stakeholder comments that the original concepts dealing with information sharing were unclear and that the process to obtain Alberta Utilities Commission (AUC) approval for an information sharing agreement could be overly burdensome. The draft regulation has narrowed the focus considerably, now limiting the scope to current and future prices and quantities of megawatts offered by a market participant, as well as any past offers that have not yet been made public. The regulation also provides specific allowances for circumstances where this information can be shared, as well as a process to request the AUC approval for information sharing in other situations that might develop in the Alberta market.

Trading Practices Guideline
The section in the draft regulation that deals with restrictions on trading using outage records that are not available to the public simply continues the practices and experience that were previously captured in the Market Surveillance Administrator's Trading Practices Guideline.

Market Share Offer Control
The draft regulation includes sections that deal with the market share offer control test. The process to determine and monitor offer control allows all market participants to plan their future growth and provides flexibility for ways to hold offer control of up to 25 per cent of the total maximum capacity of generating units in Alberta. Based on stakeholder comments, the formula included in the draft regulation to determine offer control excludes activity over the tie-lines, as these are not a specific generating unit in Alberta.

The draft regulation also includes direction to the Alberta Electric System Operator (AESO) that the price, quantity and asset identification information associated with offers to the power pool will be published with a 60 day lag, with asset identification to be replaced with offer control information when the AESO is able to gather that data in the future. This serves the original and ongoing principle of having a transparent and information rich FEOC market.

Expiry of the Regulation
A long expiry date has been included in the draft regulation to provide certainty beyond the expiration of the legislated Purchase Power Arrangements (PPAs) that currently exist. Market participants will be making investment decisions that run beyond the life of the PPAs, so long term certainty is a necessity for FEOC.

Coming into force of the Regulation
The draft regulation includes a coming into force date of March 1, 2009. This will enable market participants and agencies to implement any changes before the regulation comes into force.

The attached draft FEOC Regulation has been prepared for stakeholder review and comment. Please forward any comments you may have on the draft FEOC Regulation to Cindy.Russell@gov.ab.ca by 4:30 p.m. on October 31, 2008. Please provide your comments in the attached comment matrix.

A final regulation will be prepared after your comments have been reviewed and considered.

Thank you again for your continued input, suggestions and comments on this important work. Please contact me at Gil.Nault@gov.ab.ca or 780.422.6061 if you have any questions.

Yours truly,
Original Signed by
Gil Nault
Branch Head

Annex 3 PUCT letter re Notice of Violation by TXU Corp.

Paul Hudson
Chairman

Julie Caruthers Parsley
Commissioner

Barry T. Smitherman
Commissioner

W. Lane Lanford
Executive Director

Public Utility Commission of Texas

March 28, 2007

VIA CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. C. John Wilder
Chairman and Chief Executive Officer
TXU Corp.
1601 Bryan Street, Ste. 900
Dallas, TX. 75201

Re: PUC Docket No. ____________; Notice of Violation by TXU Corp., et al, of PURA §39.157(a) and P.U.C. SUBST. R. 25.503(g)(7)

Dear Mr. Wilder:

The purpose of this Notice of Violation (NOV) is to notify you pursuant to P.U.C. PROC. R. 22.246 that the Staff of the Public Utility Commission of Texas is recommending assessment of administrative penalties against TXU Corp., its power generation affiliates, TXU Generation Company LP, TXU DeCordova Company LP, TXU Tradinghouse Company LP, TXU Big Brown Company LP, TXU Collin Company, LLC, and TXU Valley Company, LLC, as well as their agent, TXU Portfolio Management Company LP (hereinafter collectively referred to as "TXU"). The NOV is based on TXU's failure to comply with PURA[1] §39.157(a) and P.U.C. SUBST. R. 25.503(g)(7) relating to Oversight of Wholesale Market Participants. The Public Utility Commission of Texas (Commission) may impose an administrative penalty against a person regulated under PURA who violates PURA or a rule or order adopted pursuant to PURA, as well as require a refund of monies received in connection with market power abuses.[2] The Commission may also revoke or suspend a power generation company's registration for committing market power abuses.[3] For your convenience, a copy of P.U.C. PROC. R. 22.246, which outlines your rights, is enclosed with this NOV.

[1] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§ 11.001 – 64.158 (Vernon 1998 & Supp. 2006)(PURA).
[2] PURA §§15.023(a) and 35.004(e).
[3] PURA §39.157(a).

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I. Summary of the Alleged or Continuing Violation

Market power abuse is prohibited by PURA §39.157(a) and by P.U.C. SUBST. Rule 25.503(g)(7). PURA §39.157(a) requires the Commission to monitor market power associated with the generation, transmission, distribution, and sale of electricity in the State of Texas. "Market power abuse" is further defined as "…practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level or competition...." and is defined to include "predatory pricing, withholding of production, precluding entry, and collusion." PUC SUBST. R. 25.503(g)(7) similarly prohibits market participants with market power from engaging in market power abuse, including the withholding of production.

Attached hereto and incorporated herein is a memorandum and accompanying attachments from Patrick J. Sullivan, Legal Division, recommending the assessment of an administrative penalty against TXU for numerous violations of PURA §39.157(a) and P.U.C. SUBST. R. 25.503(g)(7) for the hours from 10 to 23 during the period from June through September, 2005 (the Study Period). The details of the alleged violations are found in the attached March 2007 report of the Commission's Independent Market Monitor (IMM).[4] In summary, the IMM Report concludes that, during the Study Period, TXU had market power in the balancing energy market in ERCOT and engaged in behavior that constituted market power abuse by economically withholding production from its generation units. The IMM Report also details the impact of TXU's market power abuse:

- TXU's behavior raised prices in the balancing energy market by an estimated 15.5% during the Study Period;
- TXU profited from that abuse during the Study Period by an amount of approximately $19.6 million; and
- TXU increased the costs of the balancing energy market by approximately $70 million during the Study Period.

III. Statement of the Amount of the Penalty

Commission Staff recommends that TXU be required to pay $210,000,000 ($210 million), consisting of administrative penalties in the amount of $140,000,000 ($140 million) and refunds of $70,000,000 ($70 million). This recommendation is based upon consideration of each of the factors set forth in PURA §15.023 and P.U.C. PROC. R. 22.246. See the memorandum from Danielle Jaussaud, Wholesale Market Oversight, which is included in the attached memorandum from Mr. Sullivan.

IV. Statement Relating to TXU's Rights

Persons alleged to have committed a violation or continuing violation have a right to a hearing on the occurrence of the violation or continuing violation, the amount of the penalty,

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[4] *Report on Investigation of the Wholesale Market Activities of TXU from June 1 to September 30, 2005*, Potomac Economics, Ltd., ERCOT Independent Market Monitor, March 2007 (IMM Report). Filed in Project No. 32125, *Enforcement Program Development and Management*, on March 12, 2007.

or both the occurrence of the violation or continuing violation and the amount of the penalty. Options available pursuant to Commission rule to resolve this matter include paying the penalty, requesting a settlement conference, and requesting a contested case hearing.[5] If you wish to request a settlement conference or a contested case hearing, you must do so within 20 days of receipt of this notice. If you choose to accept the determination and recommended penalty, you must notify the Commission's Executive Director in writing within 30 days and must take all corrective action required by the Commission. A copy of P.U.C. PROC. R. 22.246 is attached to this Notice of Violation.

If you have any questions about this NOV, please do not hesitate to contact Patrick J. Sullivan, Staff Attorney, Legal Division, at (512) 936-7125.

Sincerely,

W. Lane Lanford

W. Lane Lanford
Executive Director
Public Utility Commission of Texas

[5] P.U.C. PROC. R. 22.246.

Generator Market Power
in the
Electricity Supply Industry

A review of the cause, existence and extent of controls to limit the exercise of generator market power in the British and some North American electricity markets

By

EEE Ltd

Update: July 2010

THE MARKET ABUSE LICENCE CONDITION ENACTED IN BRITAIN

History

On 8 April 2008 Ofgem launched an investigation into the behaviour of Scottish Power and Scottish and Southern Energy[1]. This followed allegations that during a four-week period in 2007 the companies (who own nearly all of the price setting plant in Scotland) abused a position of dominance that arose from constraints on the high-voltage network between England and Scotland. Namely they were alleged to have withheld generation plant from the forward wholesale market while using the same plant to supply electricity at excessive prices to National Grid in the Balancing Mechanism to keep electricity supply and demand in balance[2]. The investigation was undertaken under section 18 of the Competition Act 1998 (the Chapter II prohibition) and Article 82 of the EC Treaty. Nine months later it closed the case[3] because it decided that continuing the investigation would be an inefficient use of resources as the likelihood of making an infringement decision under the Competition Act was low. The basic problem was that while there were legal precedents for a situation where one party was dominant and exercised market power and two or more parties colluded (tacitly or otherwise) to exercise market power, there was no legal precedent for the situation of two market participants who were both dominant and could exercise market power independently of each other.

Ofgem followed up with a consultation document "Addressing Market Power Concerns in the Electricity Wholesale Sector - Initial Policy Proposals"[4]. The summary commences:-

> Ofgem is concerned that the GB wholesale electricity sector is vulnerable to undue exploitation of market power, both when there are constraints on the electricity transmission system (which limit the amount of electricity that can flow between certain locations) and more generally at times of system tightness. This vulnerability has increased over the past few years and is likely to increase further due to a number of factors such as reduced availability of transmission capacity due to maintenance outages while new investment is undertaken, a significant increase in new renewable generation connecting to the system and environmental legislation limiting the use of certain generation capacity.

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[1] Ofgem launches Competition Act investigation into Scottish Power Limited and Scottish and Southern Energy plc, 8 April 2008, http://www.ofgem.gov.uk/Media/PressRel/Documents1/Ofgem%2012.pdf.

[2] Note that in the British market there is a bilateral wholesale market (including an exchange) which functions down to an hour ahead of run time. At that point trading parties finalise their positions. Then the Balancing Mechanism by National Grid as system operator takes over, and accepts bids and offers to decrement and increment. Parties that are not in balance pay an imbalance charge based on cash-out prices from the Balancing Mechanism.

[3] Ofgem closes Competition Act 1998 case against Scottish Power and Scottish and Southern Energy, 19 January 2009, http://www.ofgem.gov.uk/Media/PressRel/Documents1/ofgem4-190109.pdf.

[4] Ref 30/09, 30 March 2009, http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/Documents1/Market%20Power%20Concerns-%20Initial%20Policy%20Proposals.pdf.

The consultation considered three broad approaches to tackling this issue:-

- Changes to existing market arrangements which included improving alignment between the incentives of the System Operator and Transmission Owners with respect to minimising the frequency and severity of transmission constraints

- Changes to existing assets and/or ownership of assets such as requiring require divestment (and/or sale of output under contract) by generators in areas where market power is thought to be present. This would require either a Market Investigation Reference to the Competition Commission, or primary legislation

- Specific mechanisms for addressing market power concerns notably a Market Power Licence Condition on generators to strengthen Ofgem's powers to carry out *ex-post* (i.e. after the event) investigations of generator behaviour and impose fines or other sanctions if participants were found to be exploiting unduly a position of market power

There are several changes to existing market arrangements which might impact on the extent of any market power that may arise and the potential for its undue exploitation. There are also a number of changes to other market arrangements that could potentially mitigate market power concerns. However, some of these proposals would only target market power issues relating to transmission constraints and none of them are likely to sufficiently address all of the concerns identified.

Ofgem attempted to introduce a Market Abuse Licence Condition[5] in 2000. But two generators refused to accept it, and the issue was referred to the Competition Commission which concluded the generators should not be forced to accept the condition. Although Ofgem made a representation to the Secretary of State to use his powers to introduce a Market Abuse Licence Condition, he declined.

The new approach

Following Ofgem's consultation in 2009 the Secretary of State determined to seek legislative powers in the Energy Bill 2010. On page 43 of the Impact Assessment[6], where it addresses potential exploitation during a constraint, there are identified two "mischiefs":-

71. Such potential actions include:

- ***First Mischief – Non-Economic Dispatch***: The generator notifying National Grid that it intends to dispatch its plant in ways that would not normally be economic given the spreads available in the wholesale market because it knows or is able to predict that National Grid will need to call on that plant in order to balance the system. (For example, this could take the form of a generator (a) submitting

[5] All generators have a generating licence which prescribes what they may do and what they may not do. Breaches of the licence can be subject to a fine.
[6] Impact Assessment of the Market Power Licence Condition (MPLC), DECC, 13 November 2009, http://www.decc.gov.uk/assets/decc/legislation/energybill/1_20100226093304_e_@@_energybillia.pdf

an intention to produce electricity from a plant in an export constrained region, despite negative market spreads, or (b) submitting an intention not to produce electricity from a plant in an import constrained region, despite positive market spreads.) A generator in these circumstances could then submit a high 'offer' into the Balancing Mechanism in the knowledge that National Grid has no alternative but to accept the excessive price. Similarly, the company might also predict a situation where National Grid would have no option but to pay for generation to be reduced at a specific plant and so 'bid' appropriately

- ***Second Mischief – Pricing Behaviour in Export Constraints***: taking advantage of both being behind an export constraint and being required to be called on by National Grid to arrange for generation to be reduced in a particular location. In such situations National Grid would have no option but to accept the 'bid' submitted. A company might also use their monopoly status in the region to extract unduly high arming fees for inter-trip contracts from National Grid

72. In their March 2009 consultation document on addressing market power concerns in the electricity wholesale sector, Ofgem estimated that of the £238m of total out-turn constraint costs in 2008/09, £125m was due to mischief. More recent estimates by Ofgem indicate that between £19m-36m of the total out-turn constraint costs in 2008/09 could be due to Mischief 1, with £106m-£115m attributable to Mischief 2. Ofgem together with consultants Frontier have modelled the forecast costs of exploitation in market power for future years and estimate that the annual costs from both mischief 1 and 2 could reach up to £520m p.a. over the next 5 years.

The limitations of Ofgem's existing Competition Powers

73. Ofgem's consultation into market power concerns followed a particular case of possible market abuse by Scottish Power and Scottish & Southern Energy that they investigated through their existing competition law powers under Competition Act 98 (referred to as the CA98 investigation). This case was closed on administrative priority grounds in January 2009, with Ofgem noting that "the likelihood of making an infringement decision under the Competition Act 1998 is low" and that proceeding with the investigation "would not be an efficient use of resources given that there are actions available which could be more effective in addressing the issues identified by the investigation on a forward-looking basis".

74. The limitation with competition law relates to difficulties in defining the electricity market, both temporarily and geographically, in which a company might exploit its position. It may also be difficult to identify legally whether a company could be said to individually dominant at any point in time, given that market power is often held by two or more companies simultaneously.

The bill became the Energy Act 2010[7]. Section 18 empowers the Secretary of State to modify licence conditions as follows (note the provisions only apply to transmission constrained situations):-

(1) The Secretary of State may modify –

[7] Energy Act 2010 part 3 – Regulation of gas and electricity markets, http://www.opsi.gov.uk/acts/acts2010/pdf/ukpga_20100027_en.pdf.

(a) a condition of a particular licence under section 6(1)(a) of the Electricity Act 1989 (generation licences);
(b) the standard conditions incorporated in licences under that provision by virtue of section 8A of that Act;
(c) a document maintained in accordance with the conditions of licences under section 6(1) of that Act, or an agreement that gives effect to a document so maintained.

(2) The Secretary of State may exercise the power in subsection (1) for the purpose only of limiting or eliminating the circumstances in which, or the extent to which, a licence holder may obtain an excessive benefit from electricity generation in a particular period ("the relevant period").

(3) The licence holder obtains an excessive benefit from electricity generation in the relevant period if –

(a) the licence holder and the transmission system operator enter into arrangements ("the relevant arrangements") (whether or not under the electricity trading and transmission arrangements), and
(b) one or more of the following conditions is met.

(4) Condition 1 is that –

(a) the licence holder fails to notify electricity generation for the relevant period that would be economic to carry out, and
(b) under the relevant arrangements, the licence holder may be, or is to be, paid an excessive amount by the transmission system operator in connection with an increase in electricity generation in the relevant period.

[This condition applies to an import constrained area to mitigate against withholding power from the wholesale market then offering high into the Balancing Mechanism].

(5) Condition 2 is that, under the relevant arrangements –

(a) the licence holder may, or is to, pay the transmission system operator an excessively low amount, or
(b) the transmission system operator may, or is to, pay the licence holder an excessively high amount, in connection with a reduction in electricity generation in the relevant period.

[This condition applies to an export constrained area where a generator offers too low into the Balancing Mechanism].

(6) Condition 3 is that, under the relevant arrangements, the transmission system operator may, or is to, pay the licence holder an excessively high amount in connection with the licence holder preparing for the possible cessation of generation of electricity by particular generating plant in the relevant period.

[This condition applies to when National Grid seeks to negotiate an intertrip agreement but the generator seeks an unreasonably high amount for the service].

(7) Condition 4 is that –

(a) the relevant arrangements relate to an increase or reduction in electricity generation in the relevant period, and

(b) under the arrangements, the licence holder may, or is to, obtain an excessive benefit.

[This condition is a general injunction against excessive bids or offers within a constrained zone].

(8) Modifications made under subsection (1) may include provision relating to one or more of the following –

(a) the operation of generating stations by the licence holder (including the amount of electricity generated and offers to generate electricity);
(b) amounts payable by, or to, the licence holder or any other person;
(c) offers by the licence holder or any other person to pay amounts.

Current status

There has been no further material published – government is working on a licence condition which will be published for consultation in the autumn of 2010, and Ofgem is working on guidelines as to how it will operate the licence conditions. The licence condition is expected to become operational next spring or summer.

Conclusions

1. Ofgem has recognised that generation licence holders do, at times, have market power across constraints and on occasions have used this market power to "obtain an excessive benefit", but it does not have adequate powers to constrain them.
2. The Secretary of State has accepted the exercise of market power across constraints by generators is an issue and has taken steps to mitigate the ability of generation licence holders to exercise their market power when the transmission network is constrained and where a licence holder might use the constraint to "obtain an excessive benefit".
3. The Secretary of State has also recognised the Competition Law has limitations in its ability to permit Ofgem to mitigate the exercise of generator market power, and has therefore implemented specific controls
4. Whilst the details of the licence provisions are still to be developed, it appears that the licence conditions will constitute an ex post assessment by Ofgem of possible transgressions by the generation licence holder with the potential for fines and/or penalties to be applied.

Appendix 5

The South Australian example

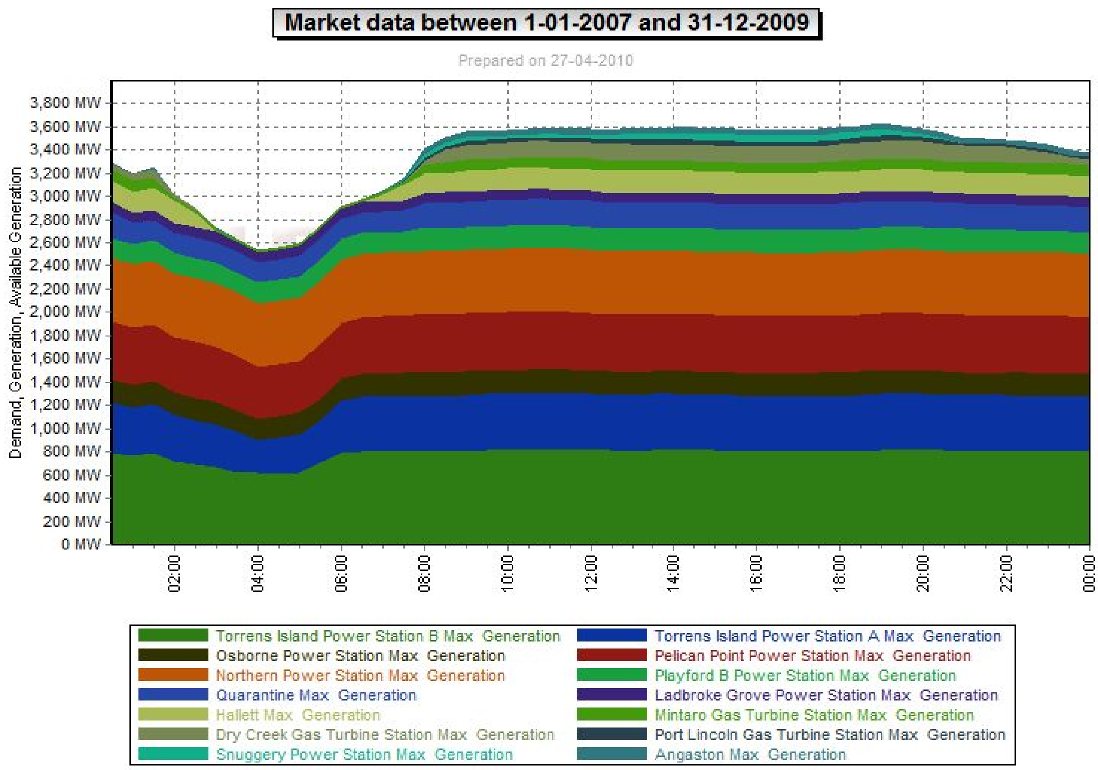
[For this section, all calculations are based on supply and demand experienced from 2007 onwards, when AGL acquired TIPS.]

A5.1 The acquisition and its impact

In 2007, the Australian Competition and Consumer Commission (ACCC) approved the purchase of the Torrens Island Power Station (TIPS) by AGL Energy. TIPS is the largest power station in the South Australian Region, by a factor of more than twice the size of the next largest power stations (Northern/Playford and Pelican Point power stations) in the region. TIPS also has installed capacity of more than twice the size of the combined capacity of the two interconnectors (Heywood and Murraylink) connecting the SA region to the adjacent Victorian region.

The installed capacity of TIPS is 36-38% of the total dispatchable capacity installed in the SA region, based on actual peak supplies from each dispatchable generator for the past 3 full years. This is shown pictorially in the following figure 5.

Figure 5: Installed dispatchable capacity in SA region

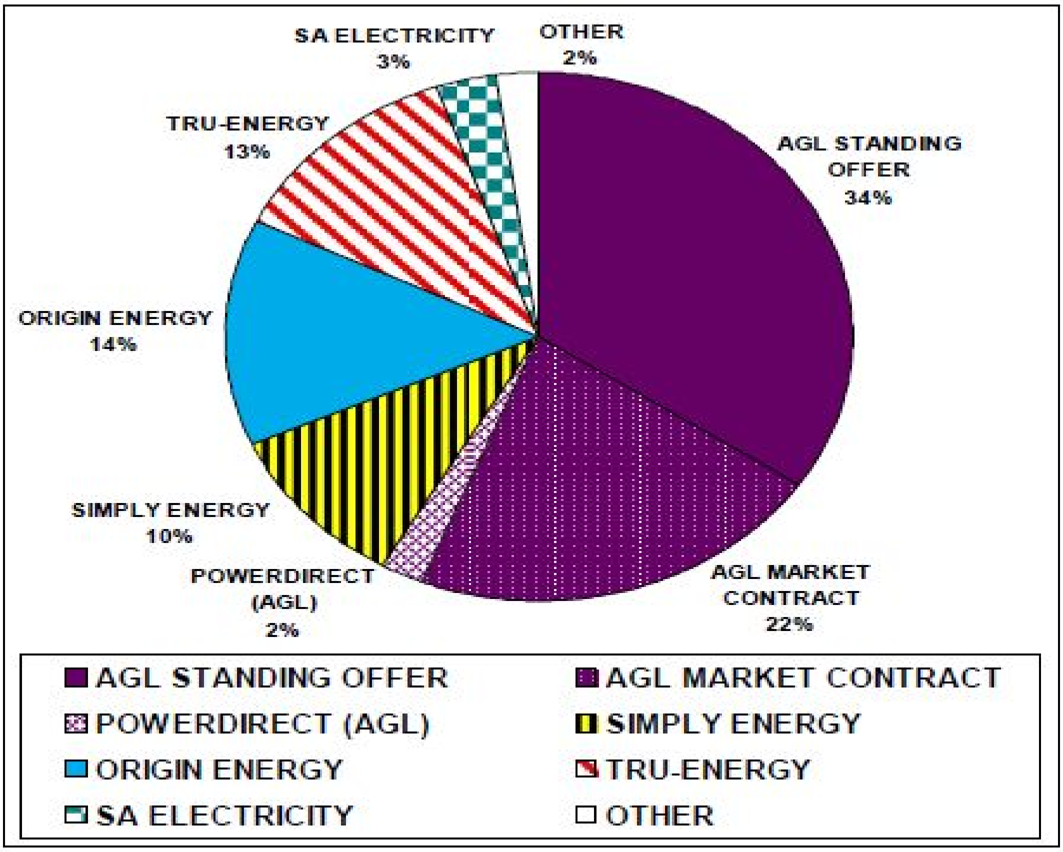


Source: NEM Review using NEMMCo data

Based on this data, in theory, even at the maximum peak demand recorded in SA to date (3331 MW on 28 January 2009), there appears to be sufficient generation in the SA region to serve this demand with an apparent 10% reserve margin[72], before including any intermittent generation and interconnector flows.

As well as being the largest generator in SA region by a large factor, AGL Energy is also the largest electricity retailer in the SA region, by a factor of four. This is shown pictorially in the following figure 6, included in the AEMC report Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia First Final Report 19 September 2008, on page xii.

Figure 6: Electricity retail market shares in SA region[73]



The important aspect of AGL being the dominant retailer is that AGL's related generator (TIPS) would not have sufficient capacity to provide the necessary generation for all of AGL retail contracts. Therefore AGL retailer would have to source significant amounts of generation output from unrelated generators to

[72] It is accepted that the peak demand occurred in midsummer and therefore many of the generators may be derated due to thermal effects, reducing this apparent reserve plant margin.
[73] Page xii, .AEMC report Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia First Final Report 19 September 2008

provide cover for its retail contracts. This need for external contracting allows AGL considerable flexibility to use TIPS output in a strategic manner to maximise AGL overall profitability. Because AGL Retail is "short" on generation for its needs but also the dominant retailer, it has a vested interest in driving up the medium to long term wholesale prices in order to profit from both its generation and retailing activities. This aspect is further developed in appendix 6.

Since AGL Energy acquired TIPS, the market has seen TIPS use its market power to increase the price in the summers of 2008, 2009 and 2010. For example, in its report Spot prices greater than $5000/MWh in South Australia 5-17 March 2008, the AER specifically comments (page 1)

> "[The] bidding behaviour by AGL significantly contributed to the high priced events. On 5, 6, 7, 12 and 13 March, **AGL was the only participant** who offered significant amounts of capacity at over $5000/MWh. In fact, around 80 per cent of capacity at AGL's Torrens Island power station was priced above $5000/MWh." (our emphasis).

In a subsequent review[74], the AER concluded that the activity of AGL's TIPS did not contravene the National Market Rules (NER). It is the MEU view that the actions of TIPS would probably have contravened the FERC and Ofgem rules on market manipulation.

A5.2 The impact of the acquisition

As noted in section 3, for the most efficient generation dispatch:

- Base generation will operate near continuously at near capacity,
- Mid merit plant will operate for extended periods of time each day at near capacity, from early morning to evening
- Peaking plant will operate for short periods of time only.

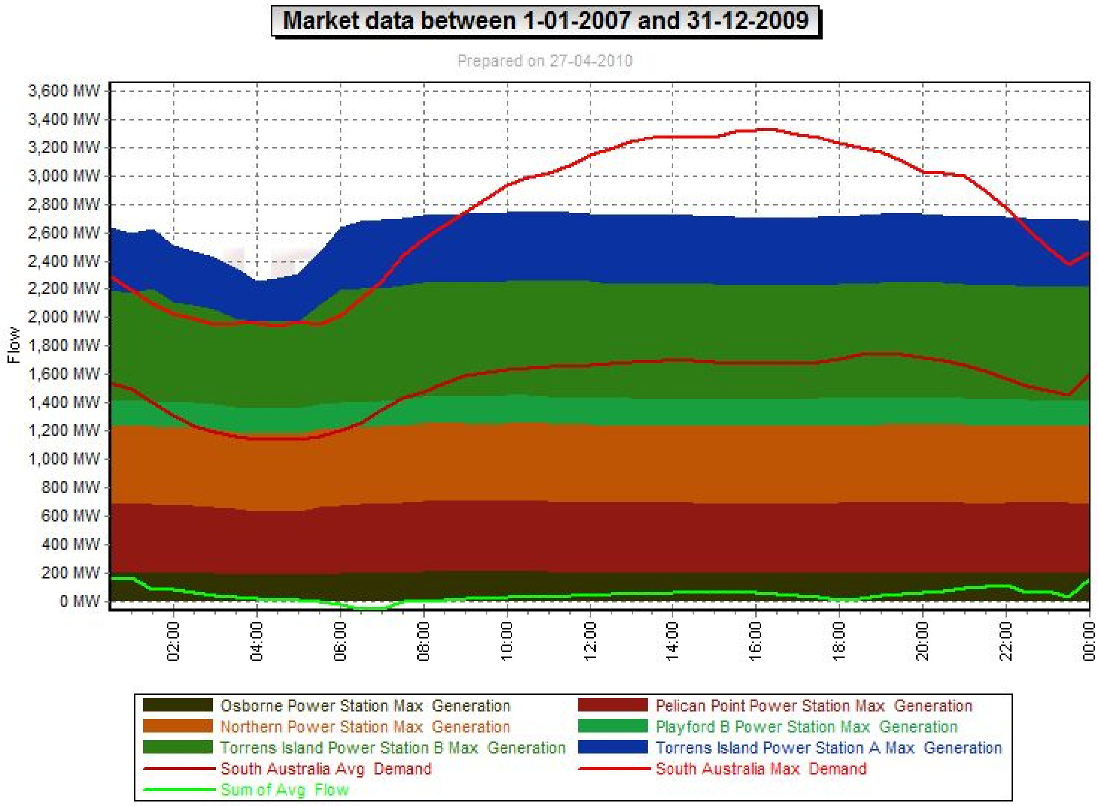
In South Australia, there are four power stations operating as base load – Northern (coal fired steam), Pelican Point (gas fired CCGT), Osborne (gas cogeneration), and TIPS B (gas fired steam). Two stations – TIPS A (gas fired steam) and Playford (coal fired steam) are used as mid merit generators because they are relatively thermally inefficient although both could be rated as base load because of their generation characteristics.

All other dispatchable generation plants in the region are classed as peaking as they are gas fired OCGT.

[74] AER Investigation Report: AGL's compliance with the good faith rebidding provision of the National Electricity Rules on 19 February 2008, May 2009

South Australian dispatch can be shown in the following figure 7. This shows generation at peak output over a day, peak and average SA demand over a day and average net import from Victoria into SA over a day.

Figure 7: SA base load and mid merit generation and imports

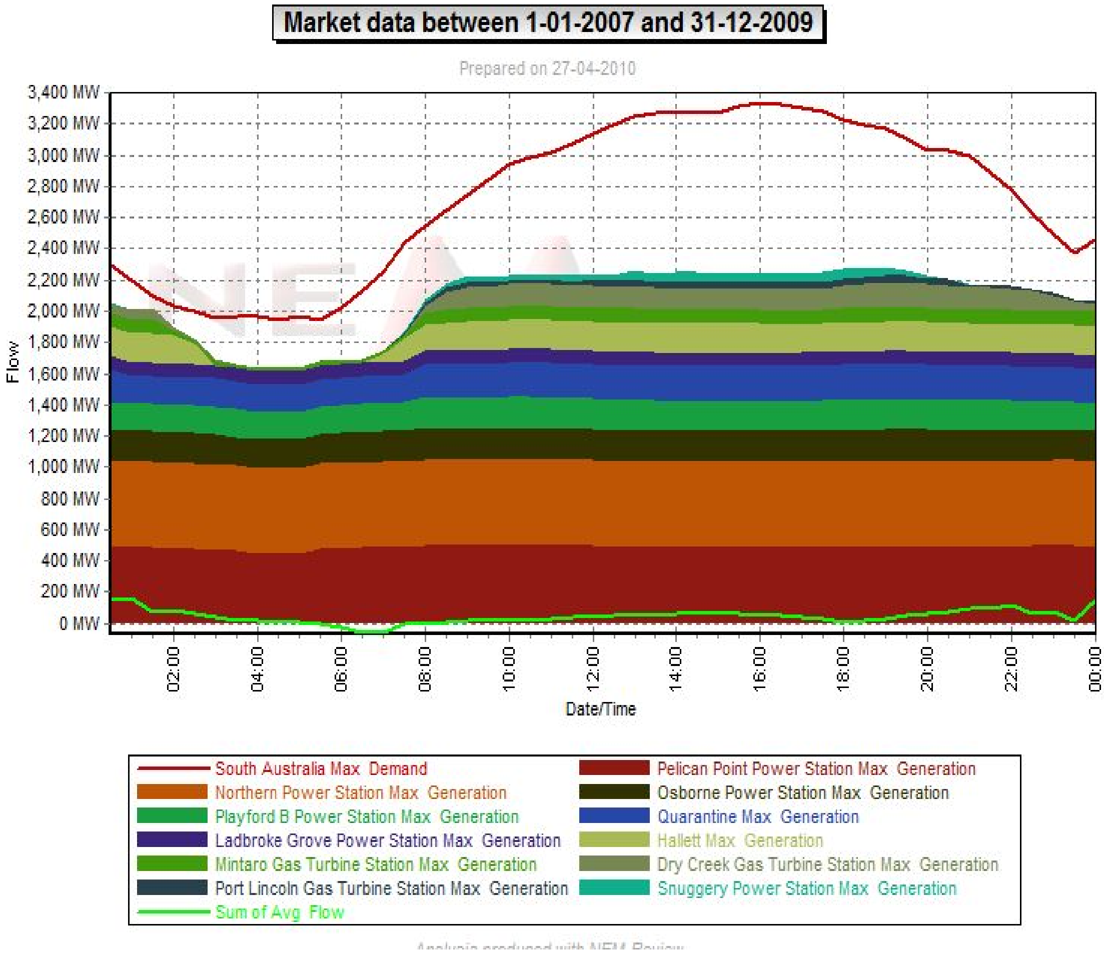


Source: NEM Review using NEMMCo data

Even assuming Osborne, Northern and Pelican Point power stations all operate at peak output continuously, and allowing average flows on the interconnectors to Victoria, TIPS A or B must operate for some of the time, even when all peaking plant is dispatched at maximum capacity.

This is so because the combined maximum generation of base and mid merit (excluding TIPS A and B) plus all of the installed peaking generation, totals ~2300 MW and the average import flow from Victoria is less than 200 MW giving a combined ability to serve demand <2500 without TIPS – this is shown pictorially in figure 8. Thus TIPS has only to “back off” supply by bidding capacity at prices above that offered by peaking plant, to force peakers to generate, and still TIPS must operate in order to meet demand.

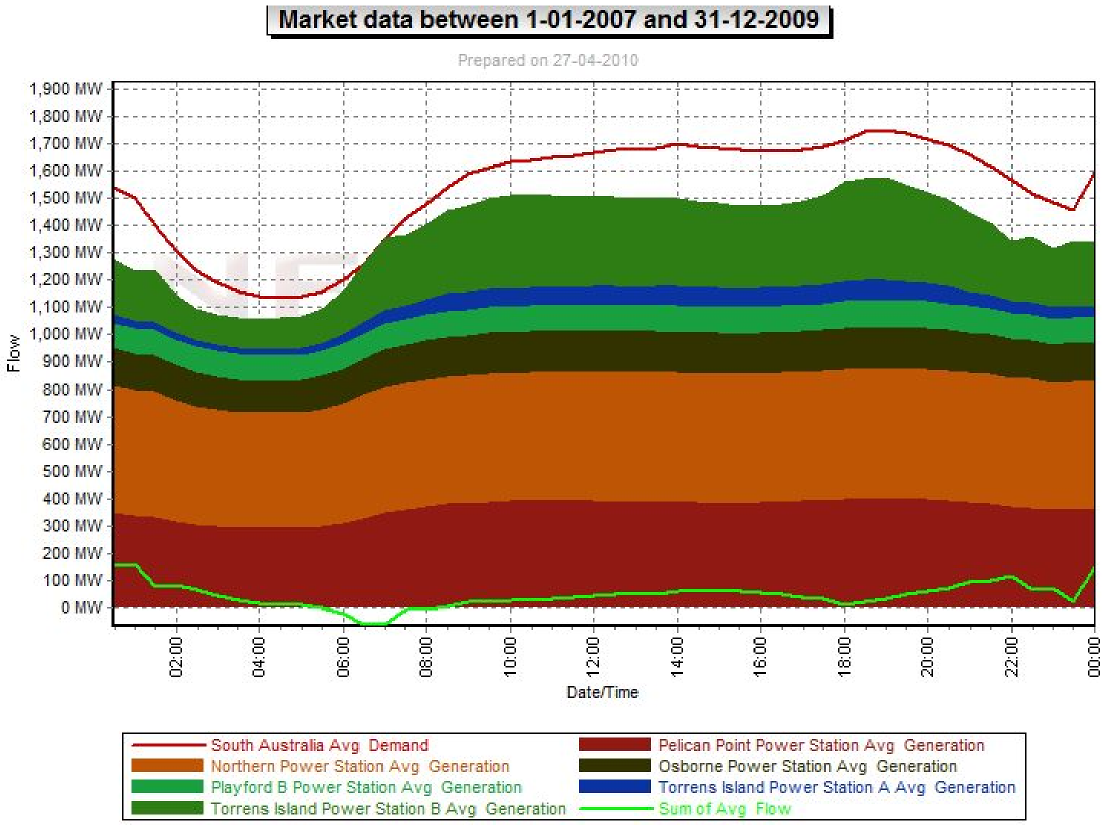
Figure 8: SA demand and dispatchable generation excluding TIPS



Source: NEM Review using NEMMCo data

Developing the same pattern but using average outputs for Osborne, Northern and Pelican Point power stations, TIPS B is still needed for dispatch even under average demand conditions, as the following figure 9 shows.

Figure 9: SA region average demand and average base load and mid merit generation



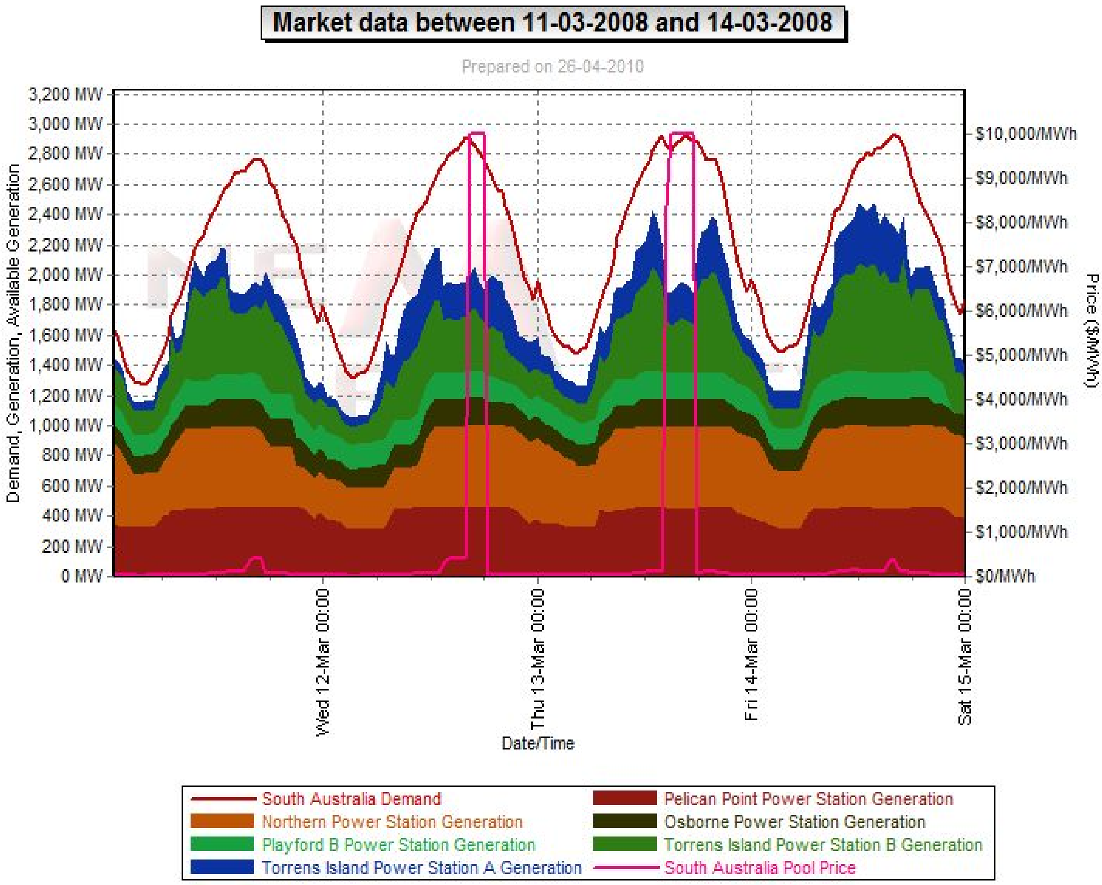
Source: NEM Review using NEMMCo data

Allowing the average output for the base load power stations (Osborne, Northern and Pelican Point), highlights the act that both TIPS B and TIPS A are needed most of the time to provide for SA demand.

Yet what is seen when demand rises above ~2500 MW, is output from TIPS B and A falls, forcing on inefficient peaking generation such as Quarantine, Hallett and others, even though TIPS A and B are more thermally efficient than the peaking stations, and have a lower marginal cost.

The following figure 10 shows that TIPS A and B actually reduced output at times when the regional demand was increasing, forcing on less efficient but higher priced generation to match demand, even though TIPS has demonstrably available capacity as before and after the high priced event, additional TIPS capacity was dispatched. On the last day (14 March), TIPS priced its output so that it would be dispatched because if it had priced as it had in the previous days, the CPT would have been breached, causing an administered price of $300/MWh to be applied.

Figure 10: SA region demand, price, and base and mid merit generation



Source: NEM Review using NEMMCo data

This clearly shows that TIPS priced its output to maximise revenue from the spot market, and that when there was a risk of an administered state being applied, TIPS deliberately changed its pricing policy to ensure that an administered state did not occur.

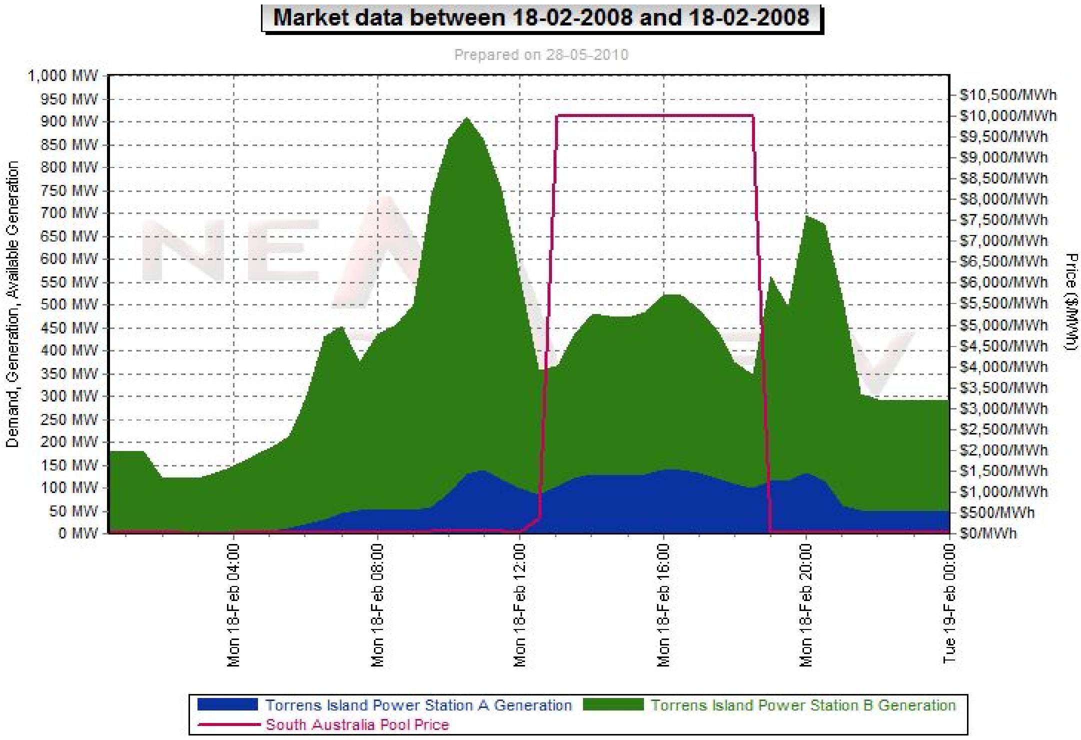
Effectively TIPS used its market power to drive the spot price up for significant periods, and when there was a risk that an administered price regime might occur, TIPS modified its pricing policy so that this did not occur.

That TIPS is not only able to so readily manipulate the spot price but prepared to do so to maximise its revenue, clearly shows it has (as a base/mid merit generator) the market power to set the spot price when the SA regional demand exceeds about ~2500 MW.

A5.3 How AGL uses TIPS – example 18 February 2008

AGL needs more that the output of TIPS to provide service to its customers. To achieve this it has to contract significant amounts of its supply with generators it does not own. The balance of its supply it derives from TIPS of which some output is not contracted to itself or to others. That this is the case is obvious from its generation pattern. The following figure 11 demonstrates this.

Figure 11: SA spot price and output from TIPS



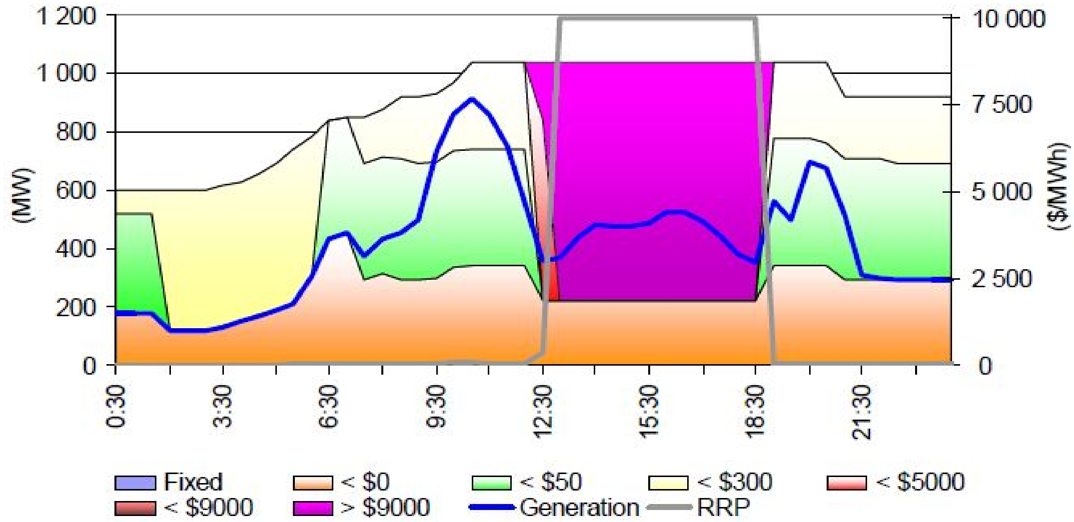
Source: NEM Review using NEMMCo data

Prior to midday on 18 February 2008, TIPS was generating at some 900 MW. TIPS bid the bulk of its capacity at prices reflecting its LRMC, but in the post midday period it bid the bulk of its output at prices approaching MPC and as a result it incurred a reduction of output of over 500 MW. Despite the reduction of sales, its revenue increased from ~$67k/hr at 10 am to over $5.2m/hr at 4 pm.

It bidding pattern is more clearly shown in the following figure 12

Figure 12: SA region price spread offers from TIPS

Figure A5: Torrens Island closing bid prices, dispatch and spot price on 18 February



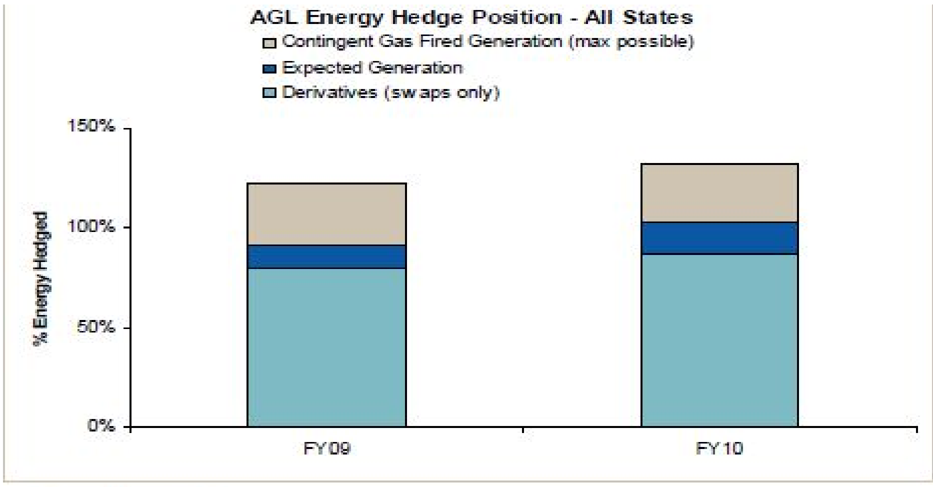
Source: AER report on prices >$5000/MWh 18 February 2008

If AGL had all of its output contracted to either itself or another party, then there would be no benefit of bidding its output near MPC as there would be no commercial benefit; in fact it would suffer a loss because of the reduced output.

When this issue was first raised in early 2008, it was stated that AGL would not continue this practice as its external contracts would "wash out" over time. In fact, AGL has continued the practice well into 2010 indicating that it intends to contract heavily with other generators and to continue using TIPS to drive up the spot and contract prices in the SA region. This is demonstrated by AGL in its presentation of results for 2009[75] and shown in the following figure 13. The figure shows that AGL is continuing its practice of hedging the bulk of its retail offerings and retaining significant amounts of generation capacity for use for other than its retail commitments, and as a result allows AGL to use the uncommitted capacity to sell into the spot market when the spot price is high.

[75]Available at
http://www.agl.com.au/Downloads/200809_ASX_FullYearResults_Presentation.pdf

Figure 13: AGL Merchant -Electricity Hedging: Position



Key Points

- Positions across all states and time periods have been aggregated
- Reference load is average annual energy (in MWh) for 100% of (C&I Contracted Load + Expected Mass Market Load)
- Expected Generation represents AGL's internal estimate of the amount of energy likely to be generated based on pool price, fuel cost and hydrology assumptions
- Contingent Gas Fired Generation is the maximum amount of energy that AGL's portfolio could generate if required
- Position does not include AGL's passive investment in Loy Yang A

Source: AGL website

The fact that AGL and TIPS can so easily manipulate the spot price (and therefore the contract prices) has been noted by many who have commented to AGL staff about this. The response is that AGL is operating within the rules and, because AGL has a responsibility to maximise revenue for its shareholders, they will continue to operate this way

Appendix 6

"Gentailer" competition in SA[76]

A "gentailer" is the terminology used for a generator which has a large direct retail exposure, and a retailer which has a large generation portfolio. In the SA market, AGL is now the largest "gentailer" although prior to its purchase of TIPS, it could be argued that TRUenergy was the largest "gentailer" in SA. Origin Energy is the other gentailer in SA. Experience in the retail market indicates that neither International Power (Pelican Point and Synergen) nor Babcock&Brown Power (Flinders Power) has a significant retail portfolio in terms of numbers of customers.

It must be noted that historically retail competition in SA in electricity has been predicated on a degree of competition in the wholesale market, when TRUenergy owned Torrens Island Power Station but did not have a retail market to fully utilise the output of the station. This meant that TRUenergy (although being one of the larger retailers in SA (along with Origin Energy and AGL) had excess generation capacity to sell, and therefore could be classed more as a generator rather than as a retailer. TRUenergy, therefore, had a driver to offer capacity to other retailers at prices that should be competitive in order to maximise the generation of power from TIPS, and thus derive its revenue.

However, the sale of TIPS to AGL results in a different situation entirely. Due to its large retail contracting, AGL Retail (which has over 70% of the retail market share[77]market in SA, and as the other large retailers have concentrated on the industrial markets, then AGL is likely to have a much higher proportion than 70% of the market for small consumers) has to have contracts with generators other than TIPS as TIPS does not have the full capacity (nor perhaps the appropriate cost structure for all of its capacity) that AGL needs to supply against its retail contracts. Thus as distinct from TRUenergy which was a net exporter of power, AGL is a net importer, and this results in a major shift in strategies for contracting TIPS capacity and any bidding behaviour that TIPS undertakes.

As AGL needs to have significant hedge contracts, particularly with the base load generators (Pelican Point, Northern and Playford) in order to match its retail load, AGL is in a unique position to utilise the output of TIPS in a way that allows it to maximise its net revenue, and to cause its retail competitors to incur

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[76] This is an extract (page 27 on) from the UnitingCare Wesley submission to AEMC Issues Paper on its Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia available at: http://www.aemc.gov.au/Media/docs/Uniting%20Care%20Wesley-b92f4cfe-f64c-4a77-ba21-061a36baf4d9-0.pdf.

[77] Bardak Ventures Pty Ltd The Effect of Industry Structure on Generation Competition and End-User Prices in the National Electricity Final — May 2nd 2005, page 26

revenue loss. Such a strategy would allow it to remain the dominant retailer in SA.

Thus in any assessment of retail competition in SA, careful analysis of the structure and capabilities of AGL with its ownership of TIPS, is essential, as it is clear that this combination (of dominant retailer with dominant generator) has the ability to change the dynamics of retail competition in SA from the situation that historically applied.

This change in focus of the "gentailer" based on TIPS from what it was to what it is now should be seen in the light of the observations by Prof Stephen Thomas Professor of Energy Studies of Greenwich University who suggests[78] (page 7):

> "In a monopoly electricity business, the retail part of the industry (purchasing power, meter-reading and billing) represents a small and simple activity. Typically it accounts for no more than 5 per cent of the cost of supplying a consumer and the risks involved are minimal and are borne entirely by consumers. However, in a fully competitive market, retail is transformed into a highly risky business. Unlike most retail businesses, electricity is entirely a standard product. This means that retailers should not be able to rely on 'brand name' or 'product differentiation' to protect their market share if their price is not the lowest. It is not possible in a network industry like electricity to buy a 'better' or a 'more prestigious' kWh of electricity. Consumers will only be interested in price and should, in theory, switch regularly to the cheapest supplier. Under economic theory, this should mean that prices will be forced down to short run marginal cost levels, levels too low to allow replacement of old assets and for new assets to be built to meet demand growth.
>
> Retail businesses are not as risky in practice as theory would suggest: consumers do not ruthlessly switch retailers frequently; they often cannot make the appropriate price comparison; the savings available do not justify their time; and they believe that buying from a trusted supplier will give them a better service. This means that electricity markets do not become ruinously competitive *because* the market is not working as a theoretically ideal market should."

Professor Thomas goes on to say (page 8):

> "Hedging contracts between generators and retailers allow generators to bypass the Pool so that the price paid or received is entirely independent of the Pool price. However, for a hedging contract to be

[78] Thomas S, "*New South Wales Government Energy Directions Green Paper*", Public Service International Research Unit, University of Greenwich, London, February 2005.

> credible, a retailer would have to be able to forecast its market share reasonably accurately for the duration of the contract. This is clearly not possible if there is a genuinely competitive retail market because market shares would vary according to competitive advantage. If a retailer goes bankrupt perhaps due to errors in market share forecasts, any contracts it has with generators become worthless. Hedging contracts have generally only been a short-term measure and most liberalised electricity systems have moved towards integration of generation and retail. The enforced break-up of traditional distribution-retail companies leaves retail businesses very vulnerable to take over.
>
> In theory, [vertical] integration is wrong, because if retail and generation are integrated, the wholesale market will be bypassed. Companies will generate to supply their own consumers directly and the wholesale market will be too little used to provide useful price signals. From a competition point of view, this is a very dangerous situation because the barriers to entry for new generators or retailers become very high. Who would a new generation company sell its power to if all the retailers had their own generating capacity? And who would a new retail company buy its power from if all the generators sold their output to their own retail businesses."

What Thomas is effectively stating is that a theoretically competitive retail market cannot provide security for consumers, as retail <u>without</u> generation is extremely risky and can leave both consumers and generators financially exposed. Equally retail <u>with</u> generation reduces competition by bypassing the wholesale market.

Thomas observes that the outcome of vertical integration results in a lessening of competition in the wholesale market and provides barriers to new entrant retailers and generators. The very fact that the ownership of TIPS has changed and that the new owner of TIPS is an energy importer reduces competition both at the retail level and the generation level, causing a lessening of competition in the SA market. However, this sale has occurred and it is very unlikely that the ACCC is able to reverse its decision allowing this merger.

Appendix 7

Futures market movements

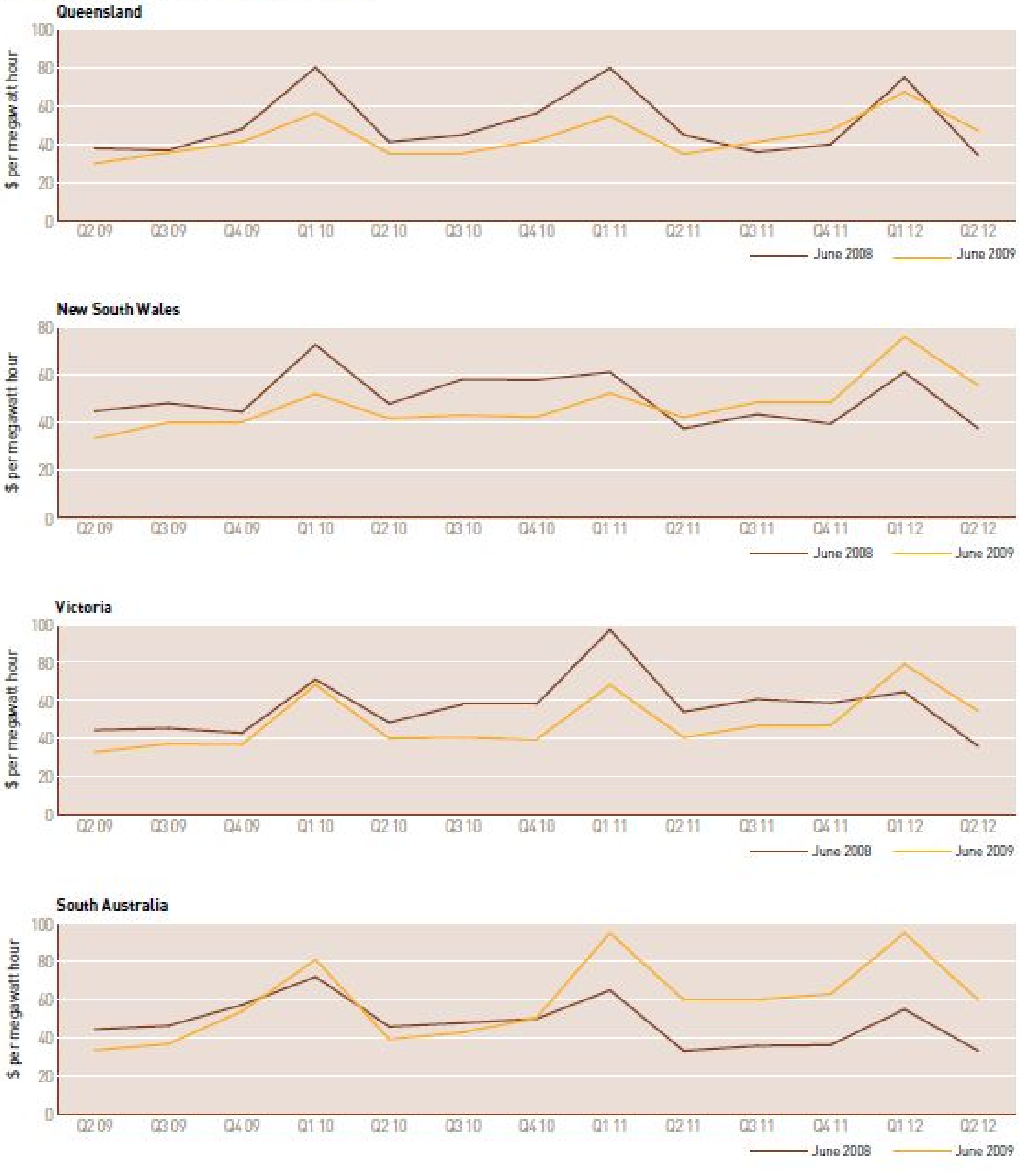
In its Sate of the Energy Market 2009 the AER observes (pages 103, 104) that

> “3.7.1 Future forward prices
>
> Figure 3.12 provides a snapshot in June 2009 of forward prices for quarterly base futures on the SFE for quarters up to two years from the trading date. These forward prices are often described as forward curves. The first four quarters of a forward curve are the prompt quarters. For comparative purposes, forward prices in June 2008 are also provided.
>
> In June 2009 prices were generally down on the levels of 2008. This might have reflected lower demand projections for the coming year (particularly for summer) and the commissioning in 2008 – 09 of almost 2500 MW of new generation capacity. South Australia was the exception, with generally higher futures prices in 2009 than in 2008. This may indicate market concerns that high prices in South Australia’s physical electricity market over the past two summers — as a result of high temperatures, interconnector constraints **and opportunistic bidding by generators** — may recur.” (Emphasis added)

Analysis of figure 3.12 (see over) provides a snap shot of the contract pricing trends experienced in the four NEM states of Queensland, NSW, Victoria and SA.

What is interesting out of the four charts in figure 3.12 is that the trends between 2008 and 2009 futures show that the three states (Queensland, NSW and Victoria) show only marginal variations between the 2008 and 2009 futures pricing (although it would appear that 2009 pricing is a little lower than 2008 pricing) but in SA the 2009 data shows a considerable increase above 2008 pricing by some 50%. This reflects the 50% trend seen in the spot markets and the anecdotal information provided by MEU members and others of the pricing trends offered by retailers in SA.

Figure 3.12
Base futures prices, June 2008 and 2009



Source: d-cyphaTrade.

Source: AER State of the Energy Markets 2009, page 104

Appendix 8

Independent Assessments of the Proposed Rule change

The MEU has sought independent assessments of its rule change proposal in relation to the approach proposed and the ability of the Trade Practices Act to limit the exercise of generator market power.

Appendix 8(a) is advice received from EEE Ltd regarding the approach proposed.

Appendix 8(b) is advice received from Dwyer Lawyers regarding the ability of the Trade Practices Act to prevent the exercise of generator market power

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30th August, 2010.

Mr. David Headberry
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Dear Mr. Headberry,

You invited me to give my opinion on the proposed Rule Change that the Major Energy Users (MEU) are proposing in order to enhance generator competition and generator outcomes during high demand periods in the National Electricity Market (NEM) by mitigating the exercise of market power[1].

The proposal refers to concerns expressed by the Australian Energy Regulator about the exercise of generator market power, particularly in South Australia by the Torrens Island Power station (TIPS), and by Macquarie Generation in New South Wales. The proposal provides some striking exhibits and tables showing how relative prices and price spikes have increased markedly in South Australia since AGL bought TIPS in 2007, along with examples of economic withholding of generation by TIPS (18 February and 13 March 2008). Appendix 2 reveals how prices and spikes have increased in South Australia as a result of actions by TIPS.

The proposal includes the report which I prepared for the MEU in 2008 as Appendix 4(a) to the document and a note on "The Market Abuse Licence Condition" recently enacted in Britain as Appendix 4(b). These appendices provide background on how the "California Crisis" precipitated action within FERC to introduce generator market power mitigation approaches, and provide a survey of the extent of concern about generator market power in:-

- Britain
- Alberta
- US North Eastern Markets
- Texas

together with the means that are deployed in those jurisdictions to mitigate generator market power.

In summary, apart from structural solutions such as divestment, there are two approaches to mitigating market power:-

[1] Market power is defined as "*the ability of either an individual supplier or group of suppliers acting in a coordinated manner (which may be explicit or tacit) to profitably maintain prices above competitive levels for a significant period of time*".

- "**Ex-ante**" approach favoured by FERC, which operates under the Federal Power Act, and whose primary regulatory goal is the attainment of "just and reasonable prices". Following the disaster in California of 2000/01 FERC has been rigorous in seeking to eradicate the exercise of generator market power. Ex-ante mitigation is applied in the US North Eastern energy markets. In this approach, before being accepted into the offer stack generator offers are compared with offers based on estimated marginal costs[2], which can be adjusted for particular circumstances such as plant needed for reliability that runs only occasionally. If the offers are unduly high they are reduced by the Independent System Operator using processes approved by FERC. An important feature of this approach is that it prevents the exercise of market power and consequently customers are not financially disadvantaged.

  In addition, to assure participants that a market is functioning in a workably competitive manner, the market operator (called in the US either an Independent System Operator or a Regional Transmission Operator) has by FERC requirement to set up an Internal Market Monitor who prepares ad hoc reports and an annual report on the behavior of the market. In addition it has to employ an external Market Monitor, who prepares an annual report on the behaviour of the market.

- "**Ex-post**" approach which is used both in the US as a backstop and in the other markets as the only approach to mitigating generator market power. In this approach there is an ex-post investigation into the behaviour of one or more generators. Typically the investigator compares the actual market pricing with a simulation of how the market would have behaved if generators had made competitive offers – the result indicates the price markup ratio. In Texas and Britain the regulator is empowered to impose significant fines. In Alberta the Market Surveillance Administrator is legally responsible for ensuring that "market participants conduct themselves in a manner that supports the fair, efficient and openly competitive operation of the market". In all jurisdictions investigations are based on strong legislative provisions

There can be no doubt that the market behaviour that is described in your proposal document of the offer behaviour by TIPS on 18 February 2008 would not be acceptable in any of the jurisdictions examined.

The proposal document provides evidence and a considered opinion that the Trade Practices Act does not provide adequate powers to mitigate the exercise of generator market power, which is not a matter which I am qualified to comment on. However the fact that TIPS has been able to exercise its undoubted market power with impunity, tends to support the contention the proposal document makes.

The MEU is primarily concerned about baseload and mid merit generators who are "dominant[3]" by exercising their market power. (The equivalent terminology used by FERC is a "pivotal" generator). To that end the MEU proposes a Rule Change which introduces an ex-ante mechanism to proscribe the offers that dominant generators can make when demand in a region exceeds the [predetermined] level to:-

- Ensure that the dominant generator(s) offer all of their available capacity to the market

- Once demand in a region increases above a level determined by the Australian Energy Regulator (AER) and which they used for determining the dominance limit, the price which the dominant generator must offer for energy is to be no more than the "Administered Price

[2] The reason why offers can be limited to around marginal costs is that these markets all have associated capacity markets and so generators receive money from both the energy and capacity markets, which in principle allows them to recover their investment costs

[3] A dominant generator is defined as one that has the ability to profitably manipulate prices in the spot market at regional demand levels below the peak demand

Cap" (APC) which is determined by the Australian Energy Markets Commission from time to time. Since the National Electricity Market is an energy only market it is expected that the APC provides a price level above the marginal cost.

In addition the proposal document requires that the National Electricity Law should be modified to give the AER the necessary powers to investigate complaints about the abuse of market power.

The proposal document shows that the Proposed Rule change will bring prices down to replicate pre 2008 levels in South Australia, and should thus remunerate all generators adequately on the assumption that the years 2005-7 are typical and generators then were adequately remunerated. You have also taken the care to consider the derogations required for a particular situation of Hydro Tasmania and the possible development in New South Wales of gentraders.

The proposal document seeks more effective mechanisms for mitigating and investigating situations of possible market power abuse than currently apply in the NEM. I consider the proposed approach is in line with those approaches used in the jurisdictions analysed in my report.

I consider the Proposed Rule change to introduce ex-ante rules on offers by dominant generators would mitigate the type of market power that concerns the MEU, appears to concern the AER based on its reports, and would concern regulators in other jurisdictions. Furthermore the Proposed Rule is simpler to implement than the ex-ante mechanisms used in the US because:

1) it does not require checking all generators, only dominant generators, and
2) it does not require the calculation of marginal costs which involves updating fuel costs.

In my opinion, the Proposed Rule is simple, easy to apply and addresses what is clearly a significant short-coming in the current NEM Rules and which would not be tolerated in other jurisdictions.

Yours sincerely,

Alex R Henney

ALEX HENNEY

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26 August 2010

Mr Bob Lim
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Dear Mr Lim

TRADE PRACTICES ACT AND GENERATOR BIDDING

Question

You asked whether the *Trade Practices Act* could protect electricity users and consumers from the consequences of generators exercising market power.

Answer

We answer "No".

While there is no general exemption under the *Trade Practices Act 1974* (the "TPA") for conduct which is permitted (but not mandatory) under the *National Electricity Law* ("the Law") and the *National Electricity Rules* ("the Rules"), there is no relevant provision of the TPA which prohibits generators exercising market power, for example through strategic bidding and economic or physical withdrawal of capacity to increase their expected revenues.

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In this regard, the national electricity market is similar to trading on Australian share or futures markets where specific legislation is required to outlaw market manipulation practices.

Background

It appears that in certain circumstances, where demand in an electricity market exceeds a certain level, the participation of a dominant generator becomes crucial. It may be profitable for the dominant generator to engage in economic or physical withdrawal of generating capacity in order to "spike the price" of electricity. While such conduct will involve windfall profits to other generators, it may still be highly profitable for the dominant generator because although it is supplying less capacity to the market, what it does supply will be sold at a far higher price.

In effect, the dominant generator turns itself into a marginal generator and baseload power is priced as if it were expensive and marginal power.

Consideration

The question, as asked, may be broken down into two sub-questions.

1. Is conduct permitted (but not mandatory) under the *National Electricity Law* and *National Electricity Rules* completely exempt, as a consequence, from the *Trade Practices Act*?

2. If the answer to question one is "No", is there any provision of the *Trade Practices Act* which applies to prohibit generators exercising market power through strategic bidding, assuming that the bidding is in good faith in compliance with the *National Electricity Rules*?

Answer to Question One - Is there a complete exemption from the Trade Practices Act?

Neither the *Trade Practices Act*, nor the *National Electricity Law* nor the legislation establishing the Australian Energy Regulator provide a complete exemption from the *Trade Practices Act* for conduct permitted under the Law or the Rules.

Formerly, the National Electricity Code was authorised by the Australian Competition and Consumer Commission ("ACCC") under the TPA. It was suggested by the National Generators Forum in a letter of 3/9/2004 from Mr G V Every-Burns to the Ministerial Council on Energy Market Reform that this meant participants following the Code could not be held to infringe the TPA. The National Generators Forum argued that when the Code was converted into legislation, market participants complying with the rules should be exempt from action under the TPA.

However, as noted by Mr. Grant Anderson of Allens Arthur Robinson in a paper of August 2004 on "Conversion of National Electricity Code into Rules under National Electricity Law" prepared for the Ministerial Council on Energy, it was not correct to assume authorisation of the former Code by the ACCC operated as a complete exemption from the TPA. In essence, only conduct *required* under the former Code or *mandated* under the new rules is completely exempt from the TPA.

The general principles of statutory construction apply. A later Act may modify the operation of an earlier Act and a specific Act and regulations made under it may modify an earlier Act.

Since there is no general exemption from the TPA for participants in the national electricity market, whether in the TPA or in the Law or in the Rules or in any other statute, the TPA may conceivably apply to permitted (but not mandatory) conduct of electricity market participants.

This is a view shared by the regulators, as evidenced by the "Memorandum of Understanding between Australian Energy Markets Commission and Australian Energy Regulator and Australian Competition and Consumer Commission" dated 2 July 2009 which states the ACCC is " responsible for functions affecting the gas and electricity industry .... including enforcement of competition laws and authorisation of anti-competitive conduct".

(We note that it may be argued that section 51(1)(b) of the TPA exempts *all* conduct of electricity market participants as that conduct is "specifically authorised" by the national electricity law as applied under the law of each State. We do not think all conduct of market participants is "specifically" so authorized and, in any case, there appears to be no express authorization as required under section 51(1C)(a).)

We therefore conclude that conduct permitted (but not mandatory) under the *National Electricity Law* and *National Electricity Rules* is not completely exempt from the *Trade Practices Act* by virtue of that permission.

Question Two - Does any provision of the TPA prohibit strategic bidding by generators?

We answer "No."

We see no relevant prohibition in the TPA.

Turning to the prohibitions in the TPA, we deal with them sequentially, noting at the outset that the prohibition of cartel conduct in Division 1 of Part IV of the TPA is not relevant to this situation.

Section 45- contracts, arrangements or understandings that restrict dealings or affect competition

Strategic bidding by a generator for supply to the electricity pool does not involve any such arrangement. There is no common understanding between the pool operator and the generator as to the purpose of the contract. Nor does the conduct involve a lessening of competition: on the contrary, it invites supply from competitors because the dominant generator is withdrawing capacity.

Nor is the conduct proscribed by the succeeding sections which develop section 45. Strategic bidding by a generator for supply to the electricity pool does not amount to an agreement to fix prices or lessen competition. Nor does it amount to a boycott. Electricity prices are set in the pool market after taking into account all bids. Nor is competition lessened by a dominant generator's making room for competitors to supply - it is enhanced, in the sense contemplated by the *Trade Practices Act*.

Section 46 - misuse of market power

Nor is section 46 violated by strategic bidding for the purpose of increasing profits. This case is quite different from predatory pricing to deter or damage a competitor.

The strategic bidding contemplated does not damage a competitor under sub-section 46(1)(a): on the contrary, the withdrawal of dominant generator capacity enriches competitors, along with the dominant generator.

Nor does it prevent the entry of persons into the market under sub-section 46(1)(b): they are free to bid into the pool.

Nor does it deter or prevent a person from engaging in competitive conduct under sub-section 46(1)(c): on the contrary, others are free to bid into the pool. If the dominant generator chooses to become uncompetitive, it does not damage its competitors.

There is no contravention of section 46 if market power is used to enrich oneself, as the "misuse" of market power requires the power be used for a proscribed purpose: *ASX Operations Pty Ltd v Pont Data Australia Pty Ltd (No 2)* (1991) 27 FCR 492 at 502; *Queensland Wire Industries Ltd v Broken Hill Proprietary Co Ltd* (1989) 167 CLR 177 at 191.

Section 52 – misleading or deceptive conduct

Strategic bidding by generators is not misleading or deceptive conduct. Indeed, it is hard to think of any conduct which could be more honest and open than a supplier to market indicating that he would like to be paid more by the market pool operator for doing less.

Common law offences

Blackstone's Commentaries describe the offences of forestalling, regrating and engrossing as offences against public trade.

The conduct of strategic bidding by a generator is remarkably similar to engrossing, which is getting large amounts of goods into one's possession so as to raise the market price at one's own discretion.

However, these offences were repealed in 1844 by 7 & 8 Vic c.24 "An Act for abolishing the Offences of Forestalling, regrating and engrossing....".

Even if they had not been repealed, these offences would not apply since electricity is not a good and a generator is not a merchant operating as middle man to buy up the supply. A generator is the original supplier.

Conclusion

We can neither find any section in the *Trade Practices Act* nor anything in the common law which proscribes the use of market power by generators to increase their revenues through strategic bidding.

We are not surprised by this legislative gap, as there are other markets where the *Trade Practices Act* is insufficient to protect purchasers from market manipulation. For example, specific legislation and legally enforceable trading rules have been required to outlaw market manipulation practices in relation to trading on the Australian share and futures markets because such practices would not otherwise be caught by the TPA.

Just as the TPA has been shown to be inadequate in preventing market manipulation in other markets and specific prohibitions and rules are required in those markets to prevent market manipulation, so it is to be expected that specific rules would be required to prevent market manipulation in an electricity pool market, such as the National Electricity Market.

Yours faithfully

Terence Dwyer