THE THEORY AND PRACTICE OF THE EXERCISE OF MARKET POWER IN THE AUSTRALIAN NEM

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This paper explores the theory and evidence for the exercise of market power in the Australian NEM as of mid-2010. This paper consists of three parts. The first part defines market power, explores the main factors that influence market power, and explores how market power is detected *ex post* or predicted *ex ante*. The second and third parts look at how market power is currently being exercised in the South Australian and Queensland regions of the NEM, respectively.[2]

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[1] Consulting economist, Australian Competition and Consumer Commission and Australian Energy Regulator. The views expressed here are those of the author and not the ACCC or the AER.

[2] The focus here on SA and QLD should not be interpreted as implying that market power is not exercised in the other regions of the NEM (NSW, VIC, TAS). Some generators in these other regions have, on occasions, exercised market power in the past. However, time constraints prevent an exhaustive audit of the patterns of market power in these other regions.

CHAPTER 1: INTRODUCTION TO THE EXERCISE OF MARKET POWER IN ELECTRICITY MARKETS

1.1 Introduction

This paper explores the theory and practice of the exercise of market power in the Australian National Electricity Market (NEM). To begin, this chapter introduces the concept of market power, explores what it means to exercise market power, and how that market power can be detected or forecast.

This chapter is organised around the following series of questions:

(a) What does it mean for an electricity generator to exercise market power?

(b) Why are electricity markets prone to the exercise of market power?

(c) How do generators exercise market power in practice?

(d) What are the main factors which affect the incentive to exercise market power?

(e) What is the difference between "unilateral market power" and "coordinated market power"?

(f) Is the exercise of market power harmful or is it necessary to stimulate investment in the NEM?

(g) How do we determine whether or not a generator has exercised market power at a specific point in time?

(h) How do we predict whether a generator or group of generators might exercise market power in the future?

(i) How do other liberalised electricity markets control the exercise of market power?

1.2 The definition of market power

What does it mean for an electricity generator to exercise market power? Across the economics literature there are a range of definitions of market power.[3] However, there is a broad consensus that a price-taking firm – that is a firm which has no influence on the market price – has no market power. Many, perhaps most, authors take this as their starting point and define a firm as having market power if it has some influence over the market price.[4] This is also the approach taken in Wikipedia, and will be the approach that is followed here:

> "A firm with market power can raise prices without losing its customers to competitors. Market participants that have market power are therefore sometimes referred to as 'price makers,' while those without are sometimes called 'price takers.' A firm with market power has the ability to individually affect either the total quantity or the prevailing price in the market. Price makers face a downward-sloping demand curve".[5]

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[3] In the broader economics literature there are a range of (more or less related) definitions of what constitutes market power. For example, the Australian Productivity Commission states that a firm has market power "if it can profitably sustain prices above the efficient cost of supply for a significant period of time". PC (2002), page 95. Baumol and Blinder (2008) define market power as the power to "prevent entry of competitors and to raise prices substantially above competitive levels". Church and Ware (2000), in a widely used economics textbook, say that "A firm has market power if it finds it profitable to raise prices above marginal cost".

[4] Hahn (1984) takes this approach: "A firm will be said to have market power if it realizes it has an influence on price. A firm will not have market power if it acts as a price taker". Similar, Rassenti, Smith and Wilson (2003) define unilateral market power as the ability "to set a price greater than marginal cost and still make positive sales".

[5] Wikipedia: Market Power: http://en.wikipedia.org/wiki/Market_power

In this paper, a generator will be said to have market power if it can, by changing its output, affect the wholesale market price that it is paid. Conversely, a generator or load which has no impact on the wholesale market price has no market power. The majority of loads in the NEM (including all residential loads and most commercial loads) and the smallest generating units (up to a capacity of, say, a few MW) have no impact on the wholesale market price and therefore have no market power. On the other hand, many of the generators in the NEM are large enough to have some impact on the wholesale market price.

It is useful to make a distinction between *possessing* market power and the *exercise* of that market power. For the reasons discussed further below, even if a generator has some ability to influence the wholesale market price, it will not necessarily choose to do so. In most instances the change in the wholesale market price that would result from a feasible variation in the output of the generator is just too small to warrant any change in the actual behaviour of the firm. A generator may have some market power – that is the ability to have some influence on the wholesale market price – but only under particular circumstances would it find it profitable to deliberately alter its offers to the market in order to influence the wholesale market price. We can say that a generator is *exercising market power* when it alters its offers to the market in a manner which is deliberately designed to alter (usually raise) the wholesale market price.

In principle, market power can be exercised by any generating unit and load which is large enough to have some impact on the wholesale market price – including both scheduled and unscheduled[6] generators and loads, and market network service providers (MNSPs). In principle, for example, an unscheduled generator might, at peak times, have some influence on the wholesale spot price and may choose to withhold output from the market[7]. In addition, market power may, in principle, be exercised by MNSPs – such as Basslink (the HVDC link between Tasmania and the mainland). However, in practice, concerns about market power in the wholesale energy market relate primarily to the behaviour of scheduled generators, which will be the focus of this paper.

Furthermore, it is worth emphasising that of course market power can in principle also be exercised in any of the other markets that constitute the NEM – including the markets for ancillary services (that is, the market for frequency regulation and contingency services) and any of the other markets or processes operated by AEMO (such as markets for inter-regional settlement residues or network control ancillary services). Concerns have on occasion been expressed about a lack of competition in the ancillary services markets, especially in Tasmania.[8] However a discussion of market power in ancillary services markets takes us beyond the scope of this paper.[9] This paper will focus primarily on the exercise of market power by scheduled generators in the wholesale energy market.

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[6] In the Australian NEM generators and loads can be categorised as either scheduled or non-scheduled. A scheduled generator or load must submit bids or offers to AEMO and must follow the dispatch target instruction that it receives in return. A non-scheduled generator or load, in contrast, is able to produce or consume as much as it likes at any point in time. There is also a third category of "semi-scheduled" generators which applies to wind farms whose output is forecast using a centralised wind forecasting algorithm.

[7] Shortly we will draw a distinction between physical withholding of capacity and economic withholding of capacity (i.e., offering a proportion of capacity at a very high price). In general I will use the term "withholding" to refer to both types of withholding – particularly economic withholding, which is more common. In this paragraph, however, we are referring to unscheduled generators so only physical withholding is possible (unscheduled generators do not submit an offer to the market).

[8] While the price for ancillary services is usually in the range of $1-3/MW in the mainland, the price for ancillary services in Tasmania has on several occasions reached the market price cap of $10,000/MWh.

[9] Market power can also be exercised in markets for transmission rights – although this has not been an issue in the NEM.

1.3 The exercise of market power

How do scheduled generators exercise market power? In a liberalised electricity market such as the NEM the outcomes in the wholesale spot market are determined by a centralised process known as the dispatch process. This process collects bid and offer information from scheduled generators and loads, information on the state of the network, and information on unscheduled load, and computes the dispatch of scheduled generators and loads, flows over the network, and the resulting prices. Therefore, at the most fundamental level, scheduled generators and loads exercise market power through the design of the bids and offers which they submit to the dispatch process.

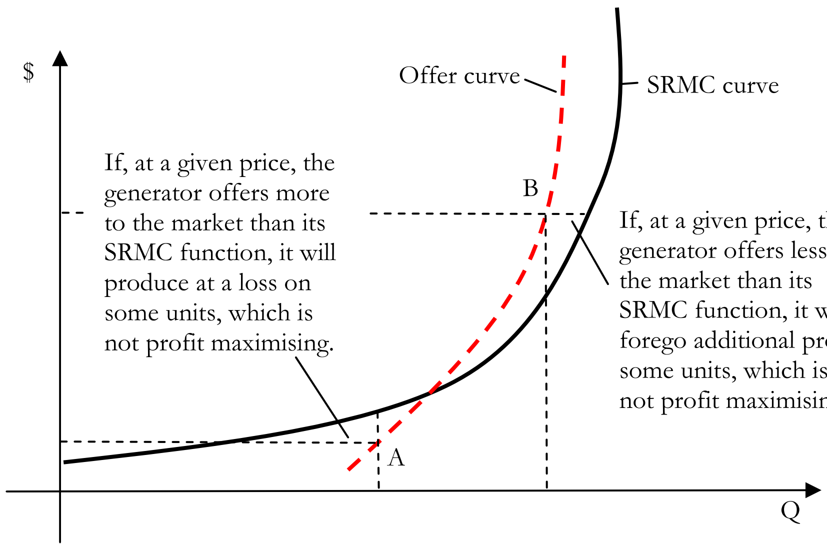
Absence of market power and bidding at SRMC

It is straightforward to verify that, for a scheduled generator, provided the generator: (a) has no impact on the wholesale spot price (i.e., is a price-taker); (b) is always dispatched to a price-quantity pair which falls on its offer curve; (c) is not bound by ramp-rate limits or minimum generation constraints, and start-up costs can be ignore; and (d) is not part of a wider collusive arrangement, that generator will offer its output to the market at a price which closely reflects its short-run marginal cost (SRMC) function – at least in that range of prices which it expects will arise with positive probability. Put simply, a price-taking profit-maximising generator (in the absence of any other market distortions) will offer its output in a way that mimics its SRMC.

This result is easily verified. Let's assume the SRMC curve of a generator is non-decreasing (i.e., increases in output do not reduce the SRMC). Suppose that, at a given price, a price-taking generator offers more output to the market than given by its SRMC function. If that price emerges in the dispatch process, this generator will be dispatched to a level of output where the marginal cost of the last unit produced is greater than the price it receives (point A in Figure 1 below). In this case this generator is making a loss on the last units it sells. This cannot be profit-maximising. Instead the generator would prefer to offer less to the market at that price.

Similarly, if, at a given price, the generator offers less output to the market than given by its SRMC function, it will be dispatched to a level where the marginal cost of the last unit produced is smaller than the price it receives (point B in the diagram below). The generator could increase its profit by producing more output at that price. Again, this is not profit-maximising, We conclude that a price-taking, profit-maximising generator that is always dispatched to a price-quantity combination on its offer curve will submit an offer curve which matches its SRMC curve, at least over the range of prices that might arise in the market.

Figure 1: A price-taking generator will offer its output in a way which reflects its SRMC curve



It is worth noting that, in the NEM, due to the NEM's regional/zoning pricing approach generators are not always dispatched to a price-quantity pair which falls on their offer curve, giving rise to incentives to submit an offer curve which does not reflect SRMC, even when the generator is a price taker. As has been studied in detail elsewhere[10], in the presence of intra-regional transmission constraints, situations can arise where a scheduled generator is not dispatched for a price-quantity combination which lies on its offer curve when it submits an offer curve which reflects its SRMC. Such a generator is said to be constrained-on or constrained-off. A generator which is constrained-on or constrained-off will typically not submit an offer curve which matches its SRMC function – even if that generator is a price-taker (i.e., has no influence on the market price). In practice, as is well known, such a generator will often have an incentive to offer all or most of its output at either the price floor ($-1000/MWh) or the price ceiling ($12,500/MWh) depending on whether the generator is constrained on or off.

This effect – the distortion of the offer curve away from SRMC due to intra-regional congestion – is sometimes put in the same basket as the exercise of market power. At a high level the two effects have some similarities - both involve a distortion in the generator's offer curve away from SRMC. However, in my view, categorising these two effects as a form of market power is unhelpful. The underlying causes of the distortion in bidding are quite different and the potential remedies are quite different. The incentive to distort the offer curve in the presence of intra-regional congestion will arise even if a generator is a price-taker. In my view, it is preferable to reserve the term "market power" for situations where a generator may, by altering its output, have some influence on the overall market price.

As we have seen, a generator which has no influence on the market price has an incentive to offer its output to the market in a manner which broadly reflects its SRMC – at least over those range of prices which may arise with some positive probability and for which the generator is a price-taker. But this does not imply that the entire offer curve of every generator will always reflect that generator's SRMC curve over its entire length. For at least two reasons:

First, in some circumstances, particular physical features of generators affect the way they offer into the market, even in the absence of any impact on the market price. For example, a generator which is not currently operating and which faces substantial start-up costs may prefer to wait until the market price is materially above its variable cost of operation before choosing to incur start-up costs. This may be reflected in an offer curve which exceeds the variable cost of operation. Along similar lines, many generators have physical minimum generation levels below which they cannot follow target levels of output. In order to reduce the risk of being dispatched to a level below their minimum generation constraint, such generators will often offer their output up to their minimum generation level at the price floor ($-1000/MWh). Such bidding behaviour is an attempt to reflect these physical features of generators within the confines of the rules of the dispatch process, and would occur even if a generator had no impact on the wholesale market price. Bidding behaviour of this kind does not constitute an exercise of market power.

There is a second reason why a generator's offer curve may not reflect its entire SRMC curve – if a generator considers that a particular price is very unlikely to arise, there is no harm in offering a quantity at that price which departs from its true SRMC. For example, if a generator forecasts that in a particular dispatch interval the price has a 99.9 per cent probability of falling between, say, $25.5 and $36.2/MWh, it may not bother to submit a bid which reflects its SRMC for the unlikely event that the price is $500/MWh. If, due to some surprise event, the price happened to fall outside the forecast range, the generator could submit a new offer for the subsequent dispatch interval with relatively little loss of profit.

In summary, what does it mean for a generator to exercise market power? At the broadest level:

> A generator can be said to exercise market power when it systematically submits an offer curve which departs from its true, underlying, short-run marginal cost curve in order to influence the wholesale spot price it is paid and is therefore dispatched to a price-quantity combination which does not fall on its short-run marginal cost curve.

[10] See, for example, the AEMC's Congestion Management Review (AEMC, 2008) and Biggar (2006).

1.4 Why are electricity markets prone to the exercise of market power?

It is widely recognised that liberalised electricity markets are prone to the exercise of market power – much more prone to market power than virtually any other industry.[11] For example, Wolak (2005) writes:

> "It is difficult to conceive of an industry more susceptible to the exercise of unilateral market power than electricity. It possesses virtually all of the product characteristics that enhance the ability of suppliers to exercise unilateral market power"

There are several reasons why electricity markets are prone to the exercise of market power:

- First, the wholesale demand for electricity is very insensitive to the wholesale price in the short run. In the language of economics, the short-run price elasticity of demand for wholesale electricity is very low. This very low price elasticity of demand arises from a number of sources. First, many consumers simply are not exposed to the wholesale price – that is, they are on retail contracts for which the price they pay is independent (in the short run) of the wholesale spot price – obviously, these consumers have no incentive at all to respond to the wholesale spot price.

  Even for those consumers who are or could be exposed to the wholesale spot price, the opportunities for inter-temporal substitution for electricity demand are often limited. In most uses, such as electricity for lighting or computing, electricity consumers require electricity to be available at a specific time. In these uses it is often hard to substitute for electricity consumption at a later time. (There may be some scope for inter-temporal substitution where electricity is used for heating or cooling and where there is some thermal inertia, or in those uses which can be deferred to off-peak times – these are often prime targets for demand-side responsiveness programmes). Although there is some limited scope for pumping water uphill which can later be used to generate hydro electricity, on the whole electricity cannot easily be stored. These factors, in combination, imply that wholesale demand for electricity is very inelastic in the short run.

- At the same time, the stock of generation assets (the capacity to generate) is fixed in the short-run. Generators typically have limited scope to "squeeze more output" when the wholesale price is high. As a result, as demand approaches the maximum capacity of the system to supply, the supply curve becomes very steep. The combination of very inelastic demand and very inelastic supply contributes to an extreme sensitivity of price to small fluctuations in the supply-demand balance at peak times. At such times even very small generators may have a significant influence on the wholesale market price.

- Binding transmission constraints limit, from time to time, the size of the area over which generators can compete with one-another, giving rise to the scope for localised market power. In extreme cases a small number or even a single generator, in what is known as a "load pocket", can effectively charge any price up to the price ceiling.

- Generators interact with each other repeatedly in the dispatch process. Using the jargon of game theory, the dispatch process is a "repeated game" between generators. The repeated nature of this game gives opportunities for generators to learn from each other, to develop reputations, to signal their intentions, and to establish implicit or tacit co-operative or collusive arrangements.

The factors above are present to a greater extent in the wholesale electricity market than in most other markets in the economy. As a result, even those wholesale electricity markets which appear,

[11] Wolak (2005), page 4. Similarly Twomey et al (2005): "There are sound theoretical reasons (and supporting evidence) for suspecting that electricity markets may be unusually susceptible at times to the exercise of market power, compared to other markets" (page 54). Wolak argues that the electricity industry requires industry-specific competition rules and regulatory safeguards "to prevent the harmful exercise of unilateral market power before it can occur and rapidly implement the necessary remedies if it does occur".

on the surface, reasonably competitive by conventional competition measures may exhibit large amounts of market power at specific times.

1.5 How do generators exercise market power in practice?

We have seen that a generator which has no influence over the wholesale price has an incentive to offer its output to the market in a way which reflects its SRMC curve (at least over a range of prices). But how do generators which can influence the wholesale price choose to offer their output to the market?

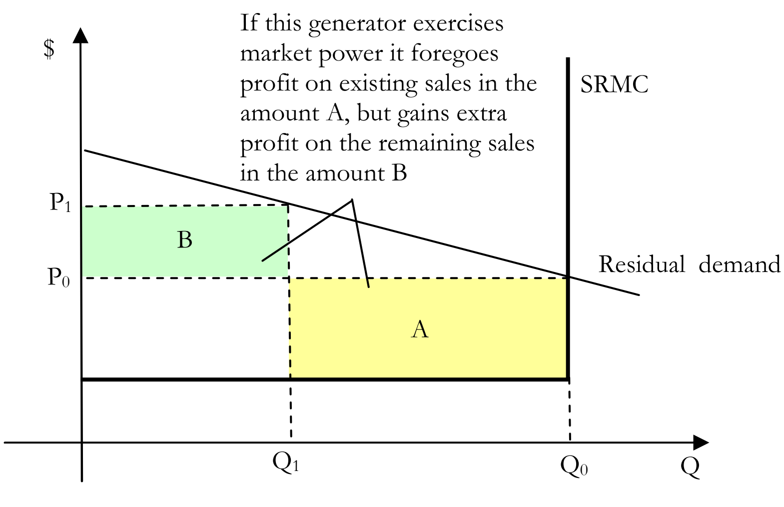
Let's focus on the unilateral action of a single generator (this analysis also applies to a group of generators who are able to establish a tight collusive arrangement). We will deal briefly with the case of an energy-limited generator later in this section.

In the language of economics, a generator with market power faces a downward sloping "residual demand curve" – that is, for each level of output that may be chosen by the generator there is some corresponding wholesale spot price; the higher the level of output of the generator, the lower the resulting wholesale spot price. We will explore shortly how a generator learns about the shape of the residual demand curve it faces.

A generator which can influence the wholesale price faces what is commonly known as a "price-volume trade-off" – that is, it can choose to be dispatched for a larger amount, receiving a lower wholesale spot price, or it can be dispatched for a lesser amount, receiving a higher wholesale spot price. Even if a generator faces a price-volume trade-off it does not necessarily have an incentive to alter its offer away from its short-run marginal cost curve. It may be that the reduction in volume necessary to achieve a material increase in the price is simply too large to justify altering the offer in any way.

This is illustrated in Figure 2 below. An exercise of market power always involves a trade-off between the margin earned on the output of the generator and the level of output of the generator. Let's suppose we have a generator with a simple stylized SRMC curve as shown in the diagram below. If this generator offers its output to the market in a manner reflecting its SRMC curve, it will be dispatched to the quantity Q_0 and will receive the price P_0. This generator may, however choose to offer in such a way that it will be dispatched to quantity Q_1 and receive the price P_1. If it does so, it foregoes the profit it earns on the extra sales (reflected in the area A), but gains extra profit on the remaining sales (area B). Whether or not this generator has an incentive to distort its offer curve away from its SRMC depends on the relative size of these two areas. If area B is larger than area A this generator has an incentive to exercise market power – that is, to alter its offer to the market in such a way as to be dispatched to the price and quantity (P_1, Q_1).

Figure 2: Price-volume trade-off in the incentive to exercise market power



The relative size of these two areas depends on factors such as:

(a) The slope of the residual demand curve (or technically, the elasticity of the residual demand curve) – the steeper the slope the greater the incentive to exercise market power. This depends in turn on the slope of the market demand curve (put another way, the volume of demand-side responsiveness) and the slope of the offer curve of other generators in the market – that is, the number and capacity of the generators which are able to expand their output in response to a price increase – which depends in turn on the nature and extent of any transmission constraints. These are all factors which are discussed in detail below.

(b) The size of the generator and, in particular, the unhedged[12] capacity of the generator (the larger the size of the unhedged sales of the generator, the greater the incentive to exercise market power for a given slope of the residual demand curve); and

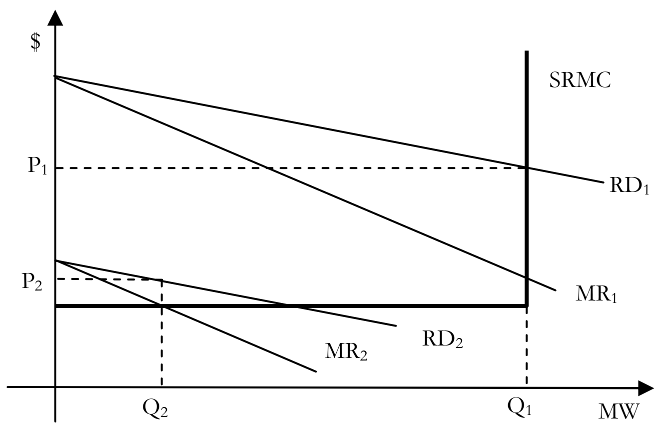
(c) The level of wholesale price relative to the variable cost of the generator. The lower the variable cost of the generator, the greater the profit on the existing sales which is foregone by a given reduction in output.

The key factors which affect the incentive to exercise market power are discussed further in the next section.

Another, slightly more sophisticated, way to view the actions of a generator with market power is as follows. Given the residual demand curve, a price-taking generator has an incentive to be dispatched up to a point where the SRMC of the generator intersects the residual demand curve. In contrast, a generator with market power has an incentive to be dispatched up to the point where the SRMC of the generator intersects the marginal revenue curve derived from that residual demand curve.[13]

This is illustrated in Figure 3 below. When the residual demand is given by RD_2 in the diagram below, the profit-maximising level of output for the generator is where the marginal revenue curve intersects the SRMC curve. The profit-maximising combination of price and output is (P_2,Q_2) and the generator is exercising market power. On the other hand, when the residual demand curve is higher (but has the same slope), at RD_1, the profit-maximising price and output combination is (P_1,Q_1) and the generator has no incentive to exercise market power.

Figure 3: A generator with market power chooses to be dispatched to where marginal revenue intercepts SRMC



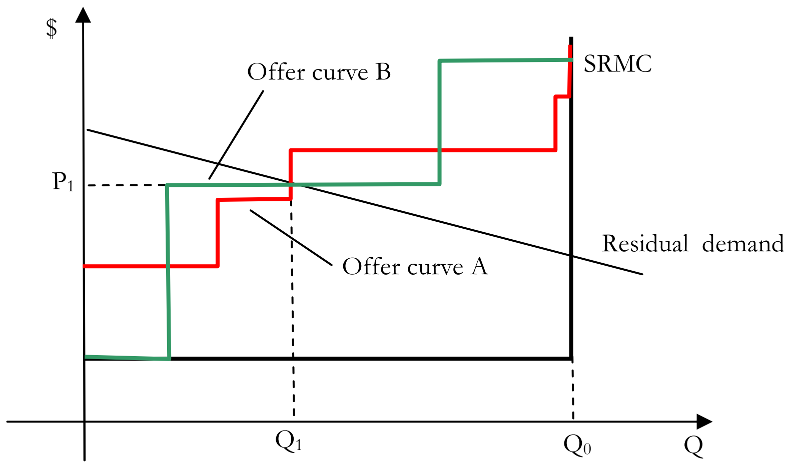
[12] We will discuss later the effect of hedging decisions on the incentive to exercise market power.

[13] Economics students learn early on that under perfect competition firms produce at the level of output where their marginal cost is equal to the market price, while monopoly firms produce at a level of output where their marginal cost is equal to the marginal revenue.

How, exactly, does a generator manipulate its offer curve to exercise market power? In principle, if there was no uncertainty, so that each generator was fully informed about the shape of the residual demand curve, each generator could compute the profit-maximising level of output and the resulting wholesale price – that is, each generator could compute the price-output combination which maximised its overall profit (which, as we have seen, is where the marginal revenue curve intersects the SRMC curve).

In the absence of uncertainty, once the optimal price-output combination is computed there are literally an infinite number of ways of designing the offer curve which achieves that point. Let's suppose the pair of price and output (P_1, Q_1) in Figure 4 below is the profit maximising combination. The generator can achieve this combination of price and output by submitting any offer curve which intersects this point. The generator can offer its output using offer curve A, or offer curve B (or any of the remaining infinite number of curves which intersect the point P_1, Q_1) and will thereby achieve a level of output Q_1 and a wholesale spot price P_1. Put another way, if the generator knew the residual demand curve with certainty, it could achieve any price-output combination that it wanted by either limiting the amount it offered to the market (i.e., economic withholding, discussed further below), or by raising the price at which it offers its output to the market (i.e., "pricing up", also discussed further below). Both approaches are entirely equivalent.

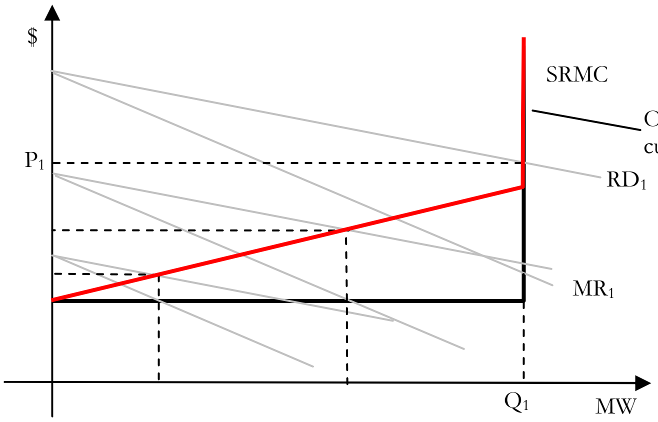
Figure 4: If the residual demand is known with certainty a large range of offer curves will achieve the profit-maximising price-output combination



In practice, the residual demand curve depends on the offer curves of every other generator in the market, the state of the network, and the level of demand. As a result the precise residual demand curve a generator will face in the future is at least partially uncertain. Therefore in practice a generator must submit an offer curve which attempts to maximise its profit over a range of possible residual demand curves.

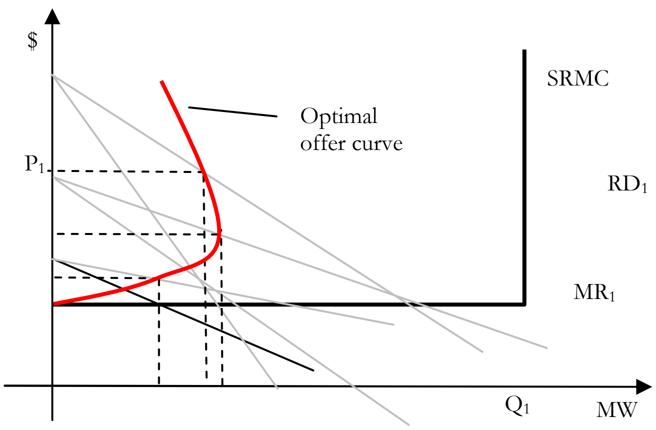
In certain circumstances computing the optimal offer curve when faced with a range of possible residual demand curves is fairly straightforward. For example, in the case where the residual demand curve has a constant slope, but only varies in its intercept with the vertical axis, the resulting locus of profit-maximising price-quantity combinations (one for each residual demand curve) is upward sloping – so the generator can simply submit an offer curve which passes through each one of these optimal combinations. No matter which residual demand curve arises in practice, the generator will be dispatched to a profit-maximising level of output. This situation is illustrated in Figure 5 below. Note that this optimal offer curve lies above the generator's true SRMC curve (although for very high levels of demand it matches the generator's SRMC curve).

Figure 5: Where there is uncertainty in the vertical position of the residual demand curve the locus of profit-maximising points falls on an upward sloping line - which is then the generator's optimal offer curve



Unfortunately, however, things become more complicated when the residual demand curve varies not only in the intercept with the vertical axis, but also in slope. In this case, the locus of points which is profit-maximising for the generator may be backward-sloping in parts, as illustrated in Figure 6 below. The market rules do not permit a generator to submit a backward sloping offer curve. The best the generator can do in this circumstance is to submit an offer curve which is vertical at the point of the bend and, if necessary, to submit a rebid if the price goes even higher.

Figure 6: Where there is uncertainty in the residual demand curve it may happen that the locus of profit-maximising points is backward sloping



The precise details as to how a generator with market power will construct its offer curve is complex (and beyond the scope of this paper). Intuitively, however, a generator with market power will generally exercise that market power by submitting an offer curve which lies above its SRMC curve, resulting in a price-quantity dispatch combination which lies above its SRMC curve.

In the simplest terms, it is often said that generators exercise market power by changing their offer curves by either reducing the quantity offered to the market at a price below the market price cap or by increasing the price at which it offers its capacity above its variable cost: First and foremost, generators exercise market power by withholding some of their output from market. It is common to distinguish two different forms of withholding: *economic withholding* and *physical withholding*.

A generator engages in *economic withholding* when it offers a proportion of its capacity at a high price – in theory any price higher than the out-turn wholesale spot price, but commonly generators exercise market power by pricing a proportion of their capacity at or near the price ceiling (which is currently $12,500/MWh – up from $10,000/MWh on 1 July 2010).

A generator engages in *physical withholding* when a proportion of its technically available capacity is simply not available to the market at any price.

Under most circumstances economic withholding and physical withholding have very similar effects on the market – they both result in a higher wholesale spot price and lower dispatch by the generator engaging in withholding. The difference between the two forms of withholding is only apparent at times of very high prices (i.e., prices at or very near the wholesale price cap). At such times, a generator engaging in economic withholding may be called on to supply some of the capacity it has priced at or near the price cap. In contrast a generator engaging in physical withholding will not normally[14] be called on to supply any more output which may result in an overall shortfall of supply relative to demand. In other words, physical withholding, unlike economic withholding, may give rise to a circumstance in which there is insufficient generation available to meet the load without involuntary load shedding. Physical withholding, unlike economic withholding, may give rise to system reliability issues.

Fortunately, under the current NEM rules, which have no direct prohibitions on the exercise of market power, physical withholding usually doesn't make economic sense for generators with market power. Once the wholesale spot price reaches the price ceiling, there is no further price-volume trade-off possible – at that point, the profit-maximising decision of the generator is to produce as much as required (as long as the price remains at the price ceiling). This can be achieved by offering that additional capacity to the market at the wholesale price cap. Under the current NEM rules, a generator can always do just as well – and will sometimes do better – by engaging in economic withholding rather than physical withholding. The exercise of market power, although undesirable for the reasons discussed below, does not normally give rise to system reliability issues under the current NEM market rules.[15] This observation might change if certain forms of withholding were made illegal. In that case, generators may find that they can more easily justify engaging in physical withholding (which implies that plant is simply unavailable perhaps for technical reasons) than economic withholding (which implies that plant is still available – but just at a very high price).

As an illustration of the economic withholding of capacity, the following chart shows the offer curves of Torrens Island Power Station in South Australia in the late morning and early afternoon of 11 January 2010. Earlier in the day and later the same day Torrens Island PS was offering around 900 MW to the market. During the afternoon peak, however, it priced around half of that capacity at the price ceiling (which was $10,000/MWh at that time). The wholesale spot price in SA, which was between $50-$100/MWh during the morning, reached the price ceiling of $10,000/MWh and remained above $9000/MWh until around 5:30 pm. Around 7 pm Torrens Island PS again offered around 900 MW to the market at a price of less than $300/MWh.

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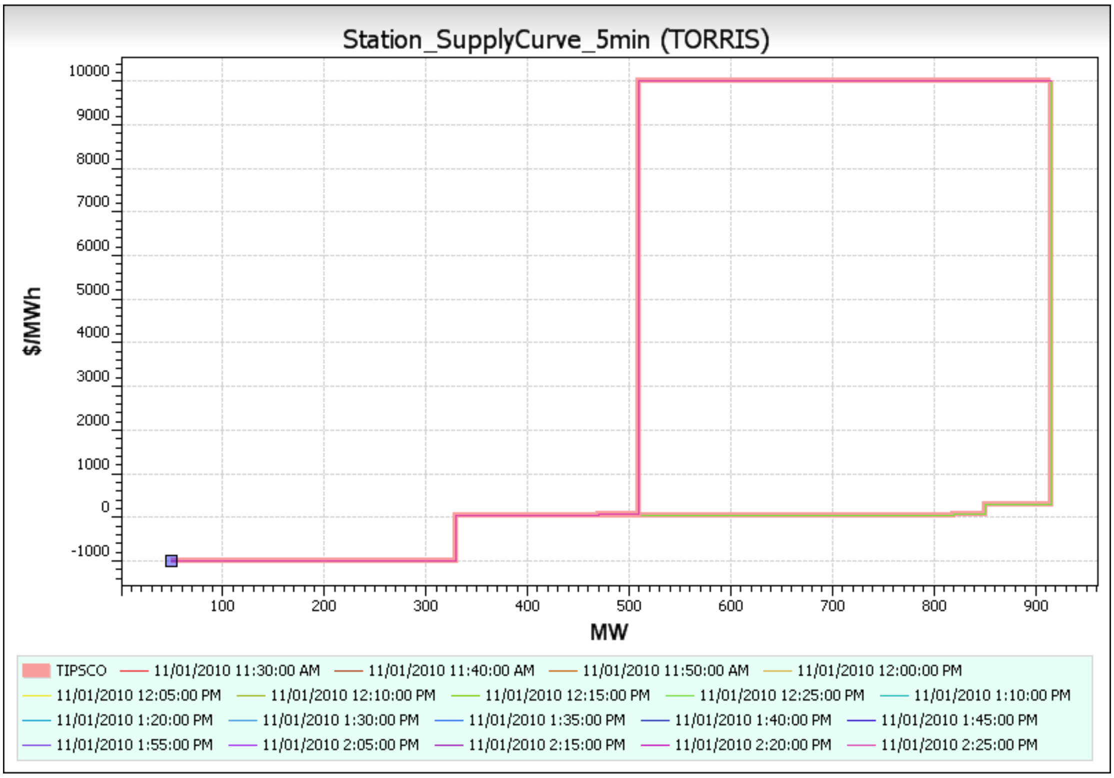
[14] In extreme circumstances, if AEMO considers that a generator is capable of producing more output AEMO can use its power to direct a generator to increase its output.

[15] There is a theoretical possibility that economic withholding could lead to reliability issues – in the presence of minimum generation levels, a large withdrawal of capacity may require some units to shut down rather than operate below their minimum stable level. If there were an unexpected increase in demand these units would not be available to the market (at least not in the short term).

Figure 7: Economic withholding by Torrens Island Power Station 11 January 2010



To be clear, it is not strictly necessary for a generator to raise the offer price for some of its capacity all the way up to the price ceiling to be engaging in economic withholding – in fact, re-pricing a proportion of its capacity to any price above the out-turn equilibrium wholesale spot price will have the same effect.

There is a particular circumstance where a generator may want to raise the offer price for all or part of its output, rather than reduce the quantity that is offered. This arises, in particular, when the generator is said to be the "marginal generator".

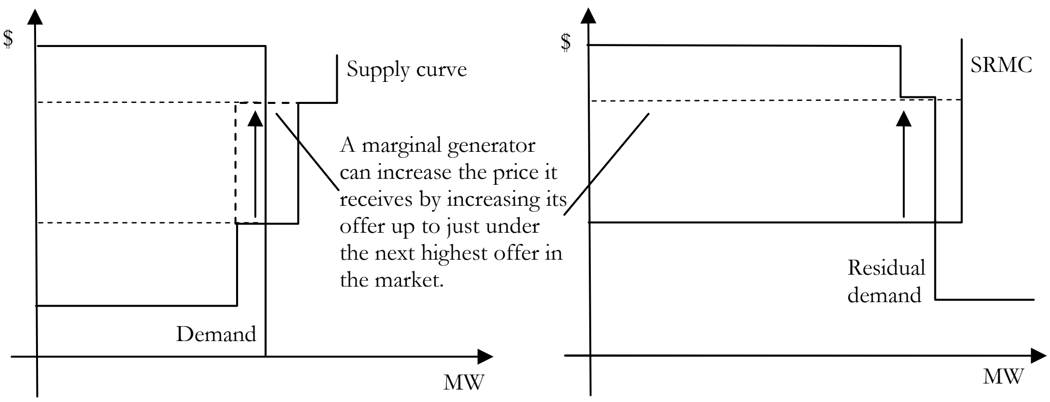
In an electricity market such as the NEM, the wholesale spot price at any specific point in time is almost always a function of the bids and offers of a very small number of certain specific generators (or scheduled loads) in the NEM – often the wholesale spot price will depend on just one generator's marginal offer. The generator(s) whose offer directly affects the wholesale spot price at a given point in time is/are said to be the "marginal" generator(s).

A generator does not need to be marginal to have an incentive to exercise market power. A generator engaging in economic withholding, for example, will not normally be the marginal generator. However, a generator that is a marginal generator does have a clear incentive to distort its offer – at least to the level of the next-highest offer in the market. This is known as *pricing up* and is illustrated in Figure 8 below.

Let's suppose that the offer curves of all the other generators in the market are known. If the generator in question offers its output to the market at a price equal to its variable cost, the generator finds that its own offer is at the point where supply and demand intersect. This results in a wholesale price equal to the marginal offer of the generator in question. However, because this generator is the marginal generator, it can raise its offer at least to the point where this offer is just under the next-highest offer in the market. This increases the wholesale spot price and, depending on the elasticity of demand, can be a profitable strategy. If demand is inelastic as illustrated here, it is always profitable for a marginal generator to increase the price of its marginal offer to the level of the next-highest offer in the market. This is known as "pricing up".[16]

The second diagram below illustrates the same effect using a residual demand curve. Given the offers of the other generator in the market, a marginal generator has an incentive to increase the price of its marginal offer to a point just under the next-highest offer in the market. Obviously, if the next-highest offer in the market is very close to the existing offer of the marginal generator, the scope for pricing-up is limited.

Figure 8: A marginal generator has an incentive to increase its marginal offer to the level of the next highest offer in the market



In conclusion, what can we say about how generators exercise market power? Scheduled generators exercise market power by submitting an offer curve which does not reflect their SRMC curve and which (usually) lies above their SRMC curve. Put simply, generators usually exercise market power by raising the price at which they offer a proportion of their capacity to the point where that capacity is not dispatched (or by simply declaring a proportion of their capacity unavailable). Marginal generators have an incentive to raise the price at which they offer the capacity they offer at the margin at least up to the level of the next highest offer in the overall supply curve.

We have seen that the incentive to exercise market power depends on the slope of the residual demand curve. But how do generators in the NEM know the shape of the residual demand curve? How does a generator know in practice whether or not it should withdraw another 200 MW of capacity, or increase its output by 200 MW?

There are different ways to estimate the shape of the residual demand curve. Generators know the forecast load profile over the course of the day, the nature and extent of any transmission outages, and the bidding behaviour of their main rivals on similar days in the past. This can be used to compute the likely residual demand curve for any particular day. Another approach (although possibly illegal under the good faith rebidding rules) is to submit a rebid and wait to see the impact of the rebid on forecast prices in the "pre-dispatch" runs – in the event the price does not rise to the extent hoped, the generator could re-bid back to the original level.

Importantly, the market systems themselves also produce regularly updated information on the forecast shape of the residual demand curve in the form of price sensitivities. Every half hour through the day the dispatch process forecasts the sensitivity of the forecast wholesale spot price to changes in the supply-demand balance – that is, the effect of an increase in demand by 100 MW, a reduction in demand by 100 MW, an increase in demand by 200 MW, and so on. This is

[16] Of course it may be possible to increase profit even more by increasing the marginal offer even further (so that it is no longer the marginal offer) – but this would then be called economic withholding rather than pricing up.

precisely the information required by a generator to estimate the shape of the residual demand curve – and therefore to decide whether or not to make a price-volume trade-off.

Such information is useful, not only in the unilateral exercise of market power but may also facilitate a form of coordination. Let's suppose that the price sensitivities published in the morning suggest that around 1 pm in the afternoon, an increase in demand (which is equivalent to a withdrawal of capacity) of 250 MW will increase the forecast wholesale spot price from \$50/MWh to \$70/MWh, and that a withdrawal of 500 MW will increase the forecast spot price from \$50/MWh to \$500/MWh.

Let's suppose that there are two large generators in this market, each willing to reduce their output by 250 MW if they can achieve at least a doubling of the wholesale price. In the absence of this price sensitivity information or any other arrangement or understanding, each generator might be unlikely to withhold any capacity – since a 250 MW unilateral withdrawal will not increase price enough to offset the fall in volume. However, if one generator withdraws 250 MW the subsequent price sensitivities will show that a further withholding of 250 MW will increase the forecast spot price from \$70/MWh to \$500/MWh – it will now be privately profitable for the second generator to also withhold 250 MW. The high degree of transparency in the NEM over future price sensitivities may facilitate either unilateral and/or coordinated market power.

1.6 What are the main factors affecting the incentive to exercise market power?

As raised in a previous section, the main factors affecting the incentive to exercise market power are the following:

(a) The hedge position of the generator (discussed further below in this section);

(b) The shape of the residual demand curve which depends, in turn, on:

- The extent of any demand responsiveness (i.e., the shape of the market demand curve);
- The willingness and ability of other generators to increase their output in response to an increase in the price (i.e., informally, the shape of the supply curve) which depends, amongst other things, on the presence of transmission constraints.
- The nature of any price caps, including the cumulative price threshold.

These are discussed in turn below.

The hedge position of a generator

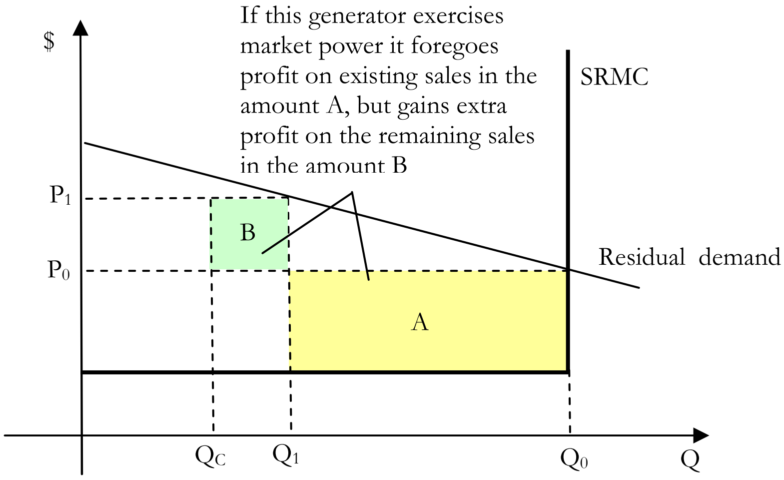
It is widely recognised that the incentive to exercise market power depends critically on the volume of output the generator has pre-sold in the forward or hedge markets.[17] With certain exceptions which are discussed further below, the sale of a hedge contract effectively locks in the price a generator will receive for the corresponding volume of its output. It no longer benefits by an increase in the wholesale spot price over that pre-sold volume of output. Any benefit from exercising market power is limited to the unhedged portion of its output.

This is illustrated in Figure 9 below, which is a variant on Figure 2 above. If we assume that this generator has pre-sold a volume Q_C of its output on the hedge market, an increase in the wholesale price only benefits the generator over the unhedged output. As a result the total gain from increasing the price on the remaining sales (area B) is greatly reduced in size relative to the case of the unhedged generator, reducing the likelihood the generator will have an incentive to exercise market power. The higher the hedge level of a generator, the lower the incentive to exercise market power and the smaller the extent to which market power is exercised when the generator chooses to do so. In the limit, if the generator is "fully hedged" (i.e., faces a hedge level

[17] See, for example, Bushnell, Mansur, Saravia (2007)

equal to its output), the generator has an incentive to offer all of its output at its SRMC no matter what residual demand curve it faces.

Figure 9: Effect of hedge level on the incentive to exercise market power



It is often argued that the effects of hedging can be observed in generators' offer curves. In particular, it is often claimed that generator's offer curves are, in effect, comprised of three separate components: (a) a portion of total capacity reflecting the minimum stable generation levels, which is offered at a level close to the wholesale price floor; (b) a portion of total capacity up to the generator's hedge level which is offered at a price close to the generator's variable cost; and (c) a portion of total capacity over which the generator may vary its output to reflect any market power and which is typically above the SRMC curve – as in Figure 5 and Figure 6 above.

Note that it is not just a generator's swap (or contracts-for-differences) position which may affect its incentive to exercise market power. Cap contracts also have a similar effect for prices above the cap strike price. In particular, if a generator holds a substantial volume of cap contracts with a strike price of $300/MWh, say, we might expect that it would not offer that portion of its capacity at a price above $300/MWh. This behaviour can often be seen in the offer curves of Snowy Hydro which is a large seller of cap contracts.

It is widely accepted that the presence of long-term fixed-price hedge contracts has a substantial impact on the incentive of a generator to exercise market power. However there are some caveats to this central result. Many (probably most) hedge contracts are of relatively short duration – between 1 and 3 years. When a hedge contract expires it is normally replaced with a new contract. The price of that contract at the time of renewal will depend on future price expectations which are likely to be influenced, at least to a certain extent, by the wholesale spot price outcomes in the past.

Put simply, a generator with a large volume of short-term hedge contracts may take the view that an exercise of market power will increase future wholesale price expectations and therefore will raise the price it receives for future hedge contract sales. In this context the generator will discount its volume of short-term hedge contracts when calculating whether or not to exercise market power. In the limit, if an exercise of market power flows directly through into increased future hedge prices, this generator can ignore its short-term hedge position when deciding whether or not to exercise market power – it is as though it is entirely unhedged.

In other words, although hedge contracts have a strong impact on the incentive to exercise market power, calculating the impact of a given level of hedge contracts on the incentive of a generator is not simply a matter of calculating the hedge position of the generator at that point in time since, as already noted, where some of those contracts are likely to renewed in the future, exercising market power today may increase the price received for future sales of those contracts, increasing the incentive to exercise market power.

Some generators in the NEM are vertically integrated with retail operations. Where these entities have entered into long-term fixed price retail contracts, those contracts will reduce the incentive to exercise upstream market power. But again, in practice we have to be mindful of the effective duration of those retail contracts. If the price at which electricity is sold at the retail level depends in some way on the average wholesale spot price, an integrated generator-retailer may retain a strong incentive to exercise market power upstream where doing so will increase the wholesale spot price and thereby the downstream retail price. This is discussed further in chapter 2 below.

Furthermore, even where the exercise of market power does not increase the average wholesale price generators may have an incentive to exercise market power when doing so increases the volatility of wholesale spot prices and therefore increases the demand for hedges. Robinson and Baniak (2002) demonstrate that generators with market power have an incentive to create volatility in the spot market.

Because hedge levels have a substantial influence on the incentive to exercise market power, it is important to understand some of the incentives of a generator to enter into hedge contracts. As a general rule, most generators seem to prefer to be hedged for a majority of their capacity. This may be due to say, covenants in contracts with their borrowers which stipulate a minimum level of hedge cover that must be maintained over time. However, in unusual circumstances generators may choose, or be forced to go unhedged.

For example, in the presence of substantial uncertainty about future market developments – such as the timing of the government's Carbon Pollution Reduction Scheme – generators may be unwilling to take on the risk of selling electricity in the forward markets. This would, in turn, enhance the incentives to exercise market power. This will particularly be the case for a generator which is only barely profitable under current market conditions and would choose to retire shortly after a CPRS is introduced. Such a generator may be unwilling to sell hedge contracts for the future in case a CPRS is introduced and the generator is forced to retire from the market.

Another issue is that the presence of market power may itself reduce the willingness of potential buyers of hedge contracts to participate in the hedge market. Let's suppose that a generator in a region has material amounts of market power. The spot price outcomes in that market will depend, amongst other things, on the overall hedge position of that generator. But a potential buyer will typically not know the overall hedge position of that generator. The buyer therefore cannot know whether or not the price it is offered for the hedge is a "fair price". The buyer may fear taking a position against a generator who can move the market in a manner adverse for the buyer. In other words, the mere presence of market power may contribute to a lack of liquidity in the hedge market.[18] As discussed further in the next chapter, this may be one factor explaining the low level of liquidity in the market for hedge contracts in SA.

Closely related to this issue, there is also a question whether or not a generator with substantial market power could legally sell a hedge contract without violating the laws against insider trading – since it would be entering into a transaction in which it had information not generally available to the market (it's current and likely future hedge level) which affected future market outcomes.

To make matters more complicated, the overall hedge position of a generator is not typically exogenous (that is, decided by factors other than market power) but may itself depend on opportunities to exercise market power. Even if a generator desires to be hedged to, say, 75 per cent of its capacity on average, on those days where it is likely to have substantial market power it may choose to leave itself largely unhedged so that it retains the incentive to raise the price.

Furthermore, it is important to note that the "hedge position" of a generator is not necessarily a single number but perhaps should be better thought of as a *function* which depends on the wholesale spot price. For example, even if a generator doesn't know when in the future opportunities for market power will arise, it may know that such opportunities are more likely to arise when the spot price is already high. A 1000 MW generator could sell a swap contract for, say, 1000 MW and then purchase a cap contract with a strike price of $300/MWh for 1000 MW.

[18] See Biggar (2011).

In effect the generator would be fully hedged when the price is below \$300/MWh and completely unhedged when the price is above \$300/MWh. As soon as the wholesale spot price increases above \$300/MWh this generator would retain the incentive to exercise any market power that it might have at such times.

Overall, although hedge levels have a strong impact on the incentive to exercise market power, the relationship between a generator's actions in the forward market and its actions in the spot market remains incompletely understood.

One final point can be made about the link between market power and hedge contracts: transmission rights of various kinds – such as inter-regional settlement residues or financial transmission rights (which do not currently exist in the NEM) also have a substantial impact on a generator's incentive to exercise market power. However this takes us beyond the scope of this paper.

The presence of transmission constraints

In addition to hedge contracts, the presence of transmission constraints can also have a significant impact on the incentive to exercise market power.[19] In the case of meshed[20] networks the effect of transmission constraints on prices and dispatch is quite complex and would take us beyond the scope of this paper. For the moment, let's focus on simple radial networks.

In any electricity industry, the impact of an exercise of market power by a generator, (usually in the form of a withdrawal of capacity) depends on the willingness and ability of other generators in the market to increase their output in response to the withdrawal, together with the willingness and ability of loads to reduce their demand. When other generators in the market are operating at their physical limit they no longer have the ability to offset the withdrawal of capacity – this tends to increase the market power of the remaining generator.

In exactly the same way, transmission constraints can serve to limit the ability of generators in other regions to increase their output in response to a generator exercising market power in a particular region. This tends to increase the market power of the generators in the importing region. We can express this another way: Using the language of competition policy we can say that transmission constraints reduce the geographic scope of the relevant market – reducing the number of generators in direct competition with the generator exercising market power.

In a simple radial network, transmission constraints have two quite different effects depending on whether the binding transmission constraints are in the importing or exporting direction. Let's consider first the case where the relevant transmission constraints are in the *importing* direction (i.e., with the flow towards the generator(s) exercising market power).

When a generator withdraws capacity from the market, this tends to tighten the supply-demand balance in its region, raising the price in that region, and inducing an increase in the output of other generators in that region, and an increase in the output of generators in other regions. This, in turn, tends to increase the flow on the transmission lines into that region. If the flow is initially in the export direction, the flow on the transmission line may reverse and the region may start importing. If the withdrawal is large enough, it may cause the import flow to reach the import limit on the transmission network. At this point, the generators in the other regions can no longer increase their output in response to any further withdrawal by the generator with market power – generators in other regions can no longer compete. The only generators who can now serve to mitigate the effects of the market power are generators (or loads) internal to that region.

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[19] See Joskow and Tirole (2000), Borenstein, Bushnell and Stoft (2000), Gilbert, Neuhoff and Newbery (2004).

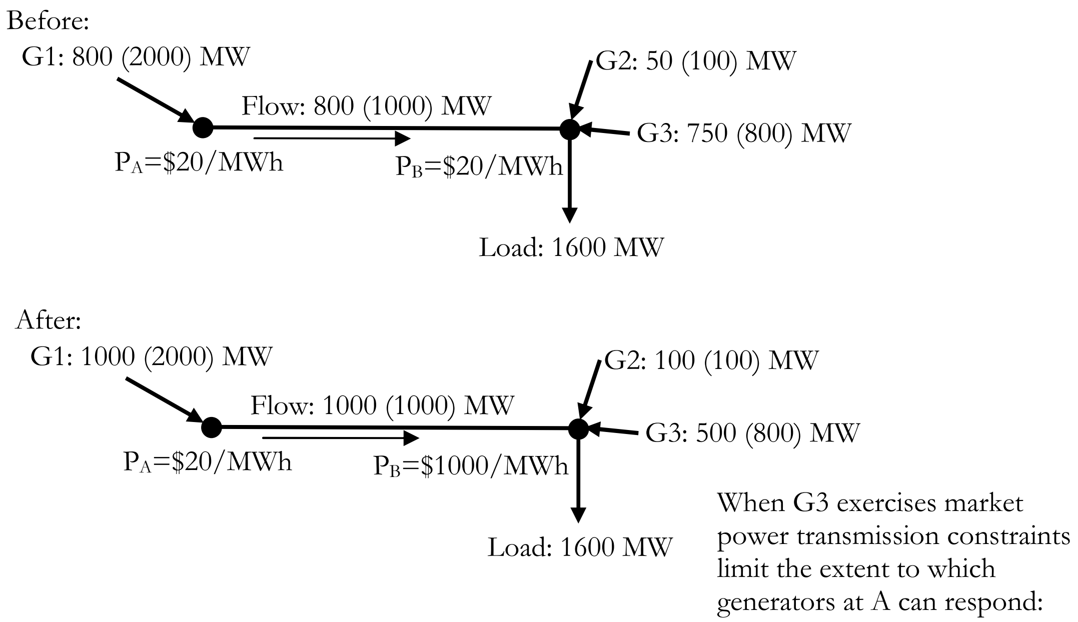
[20] It is often useful to draw a distinction between "meshed" networks and "radial" networks. Meshed networks have more than one path between two points on the network. In the case of radial networks, in contrast, for any two points on the network there is only one path between those points. Pricing and dispatch is much simpler on radial networks. Almost all real-world transmission networks are highly meshed.

If there are few such generators (or if they are already operating at their physical limit) the generator withdrawing capacity may have very substantial market power.

This is illustrated in Figure 10. This diagram illustrates a simple electricity network with two regions and one transmission link. There are three generators and one load. After each generator is a number reflecting its instantaneous output and a number in brackets reflecting its maximum capacity. Initially the generator at node A is producing 800 MW, all of which flows down the transmission link. The two generators at node B produce the remaining 800 MW which is sufficient to serve the load of 1600 MW at load B.

Now let's consider what happens when the generator G3 withdraws capacity from the market. The immediate response is for the other generators to increase their output. However, the generators at node A are limited by the transmission constraint. They can supply no more than 1000 MW of power into region B. The other generators in region B can only supply 100 MW of power. As a result, by reducing its output below 500 MW, generator G3 can increase the price in region B significantly. In this example generator G3 is a "pivotal" generator whenever demand at node B increases above 1100 MW.[21]

Figure 10: Import transmission constraints can result in significant market power



A related effect happens when the generator with market power is in an exporting region (such as generator G1 in the diagram above). In this case, when the transmission line out of the region is binding in the export direction, the remote region is, once again, effectively in a separate market for the purposes of competition analysis. Any withdrawal of capacity from the local region will tend to alleviate the transmission constraint but as long as that constraint remains binding, any withdrawal of capacity by a generator in the exporting region can only be offset by generators in the same region. If there are few or no other generators in the local region, a generator withdrawing capacity may have significant market power.

However, unlike the case where the transmission constraint is in the importing direction, there is a limit to the market power of a generator in an exporting region – the generator can, at most, withdraw capacity to the point where the prices are equalised in the two regions and the

[21] A generator is pivotal in a region if its output is required to meet the load in the region (taking into account the potential output of other generators and transmission lines into the region). This is discussed further in section 1.9 on page 29.

transmission constraint is no longer binding. Any further attempt at withdrawing capacity will now be met by a response by generators in both regions. In the diagram above, if generator G1 had substantial market power we would expect that, at those times when the transmission constraint was binding and there was a high price at node B, generator G1 would respond by reducing its output just enough to eliminate the transmission constraint and thereby ensure prices were equalised across the two regions.

In other words, market power can both exacerbate and alleviate transmission constraints. Market power tends to exacerbate transmission constraints on import flows into regions with significant market power. At the same time market power tends to be used to alleviate transmission constraints on export flows from regions with significant market power.

One immediate consequence is that even if there are no observed binding transmission constraints in a market, it does not imply that transmission constraints are not affecting the behaviour of generators – generators with market power could be using that market power to ensure that export constraints do not, in fact, bind.

As we will see in the next chapters, the exercise of market power in the Australian NEM tends to be strongly linked with the presence of constraints on the transmission network. In the absence of transmission constraints relatively few generators in the NEM are able to exercise market power and then only infrequently. However, as we will see, transmission constraints bind frequently enough to allow some generators or groups of generators to exercise material market power. Generators in Queensland, for example, tend to exercise market power when the transmission constraints between New South Wales and QLD are binding in the northerly and southerly directions – in which case the exercise of market power has the effect of equalising the prices between NSW and QLD.

The analysis above focused on the case of single generator with market power in a simple radial network.[22] More complicated outcomes are possible when a generating firm owns (or controls) many generating stations located at different places in the network, and potentially on different sides of a transmission constraint. In this case it may make sense for the firm to increase the output at its plant upstream of a transmission constraint in order to cause an export transmission constraint to bind, allowing its generating plant in the importing region to benefit from substantial market power. The presence of loops in the network complicates matters even further, taking us beyond the scope of this paper.[23]

Other factors

The sections above have emphasised the impact of hedge contracts and transmission constraints on the incentive to exercise market power. Other factors which affect the incentive to exercise market power include:

(a) The shape of the wholesale market demand curve. The greater the degree to which the wholesale demand responds to the wholesale price, the "flatter" the residual demand curve, the greater the withdrawal of capacity that is required to achieve any given price, and therefore the weaker the incentive to exercise market power. Increasing demand-side responsiveness or increasing the extent to which load serving entities participate in the wholesale market can be an important tool for mitigating wholesale market power.[24]

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[22] For further studies see Borenstein, Bushnell and Stoft (2000), Oren (1997), and Joskow and Tirole (2000).

[23] "Cardell, Hitt and Hogan (1997) show that, if strategic generators own generation assets at node A and B of a three-node network, they might increase output at node A relative to a competitive scenario if this reduces the energy delivered to node B due to loop flows and therefore increases prices at node B". Twomey et al (2005).

[24] See Rassenti, Smith and Wilson (2003).

(b) The shape of the wholesale market supply curve and the structure of the wholesale market. The greater the degree of competition at all points on the supply curve the lower the incentive to withdraw capacity.

(c) The wholesale price cap and the cumulative price threshold. Other things equal, the higher the wholesale price cap, the greater the incentive for a generator to exercise market power (particularly when the generator is able to increase the price to the price ceiling). Once the price cap is reached a generator has no further incentive to exercise market power (no further price-volume trade-off is possible).

This last point is worth discussing further. In addition to the wholesale price ceiling in the NEM there is another wholesale price cap which directly affects the incentives to exercise market power – the Administered Price Cap or APC. The APC is applied once the sum of 336 consecutive trading interval prices (i.e., 7 days) exceeds the Cumulative Price Threshold or CPT. (currently $187,500). Once this threshold has been exceeded in a region, the APC is invoked and the wholesale spot price for that region is limited to a level chosen by AEMO (typically $300/MWh). Once invoked, the APC remains in place until the end of the trading day during which the rolling sum of prices falls below the CPT. Once the APC has been invoked, a generator has no incentive to use its market power to increase the wholesale spot price above the APC (typically $300/MWh).

Importantly, the threat of the APC may have an impact on the timing as to when a generator chooses to exercise market power. The APC essentially limits the average wholesale spot price over a seven-day period. As we have seen, not all opportunities to exercise market power are equally profitable to a generator. On one occasion a generator may have to withdraw only a small amount to induce the wholesale spot price to rise to the price cap. On other occasions the generator may have to withdraw a large amount to induce the wholesale spot price to rise to the price cap. Clearly, those occasions when the generator need not withdraw as much capacity to increase the wholesale spot price are more profitable for the generator. A generator faced with several opportunities to exercise market power in a seven day period may prefer to ration those opportunities and only take up the most favourable opportunities, especially when the cumulative price is already very high. As we will in chapter 2, it is possible to detect a few occasions where a generator with market power appears to not take up an opportunity to exercise market power when the cumulative price is very high and the exercise of market power is likely to trigger the APC.

1.7 What is the difference between "unilateral" and "coordinated" market power?

The discussion above has focused on analysing the incentives of an individual generator, acting alone, to exercise market power. In the language of competition policy, these are known as "unilateral" effects.

However it is well known that in markets with repeated interaction of the same players, the players start to recognise their mutual interdependency and will often begin to adopt accommodative strategies which are in their mutual interest rather than just in their private self interest. In the language of competition policy, these are known as "coordinated effects". [25]

Coordinated effects are more likely to arise in markets with repeated interaction of a small number of players; where the market structure is stable (that is no new entry or exit and where innovation is low); where there is a high degree of transparency; and where the gains for co-operation are large relative to the non-cooperative outcome.

As already mentioned, generators in the NEM interact with each other repeatedly on a long-term basis. Entry of large scale new players is relatively rare, with many years between major entry or exit events. In addition the Australian NEM features a very high degree of transparency – the bidding behaviour of every generator is available within 24 hours and information on price

[25] Sweeting (2007) finds evidence of tacit collusion in the England and Wales wholesale electricity market.

sensitivities is available every half hour. Finally, as we have seen, the gains from collusive arrangements can be very large. It is possible to increase the price very significantly on certain occasions. As a result it would be surprising if some form of implicit arrangements or understandings did not arise between generators.

These understandings may take many forms and may allow collusive outcomes to be sustained over time. It is difficult to say anything general about the scope or nature of these understandings. However we might make the following comments:

(a) First, such arrangements or understandings are more likely to emerge in a period of stability in the market – particularly stability in the players themselves, the rules, and the overall market conditions. Conversely changes in the market, such as the introduction of a new generator, the change of ownership of an existing generator (particular a privatisation), a merger or divestiture, a change in the capacity of the interconnectors, or a change in market conditions (such as the introduction of the CPRS) may disrupt any existing arrangement and result in a period of "instability" (i.e., competitive behaviour) before a new market arrangement emerges.

(b) Second, such arrangements or understandings are more likely to emerge in a period of general over-capacity in the market, when the consequences of failing to reach an arrangement or understanding are more serious for the market participants. In a time of general over-supply of the market, the equilibrium pool price in the absence of coordination could be quite low. In this context, achieving a degree of coordination can appear particularly attractive. Conversely, in those times where there is a shortage of capacity in the market, unilateral exercise of market power is more attractive.

One possible way to informally coordinate behaviour among different generators in the context of changing market conditions is simply to reach an understanding that the market will be shared equally between the different generators – that is, that the market share of each major generator will remain roughly constant over time. This approach has at least two advantages:

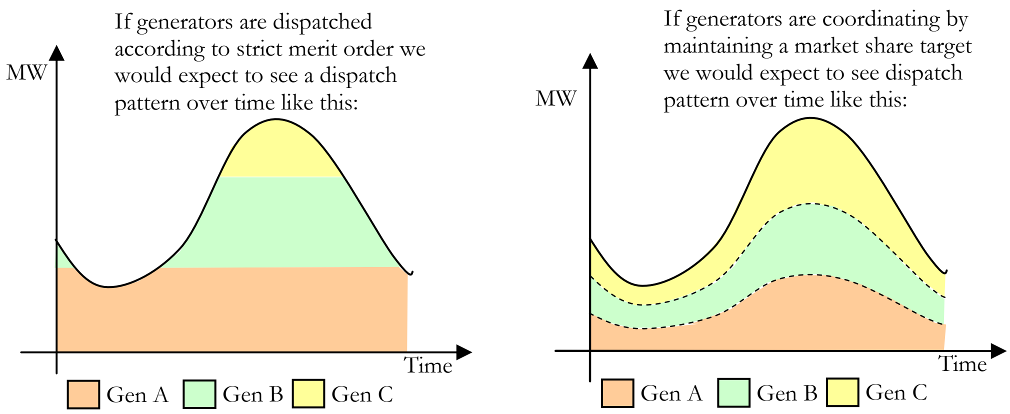
- First, deviations from this arrangement can be relatively quickly and easily detected (each generator can observe its own output and total regional demand and is able to quickly assess its instantaneous market share). Deviations can therefore be punished by reverting to a non-cooperative outcome.

- Second, if any generator in the arrangement withholds capacity from the market, the other generators must do likewise, in order to maintain their market share. If any generator departed from the arrangement and offered more of its capacity to the market at a high price time, that generator would be dispatched for more, and its increased market share would be quickly detected.

In order for generators to maintain their market share, it must be that their offer curves all have the same shape. In effect, the generators must "interleave" their offer curves in the overall supply curve for the region. This results in quite different dispatch patterns than if all the generators were dispatched according to their simple merit order.

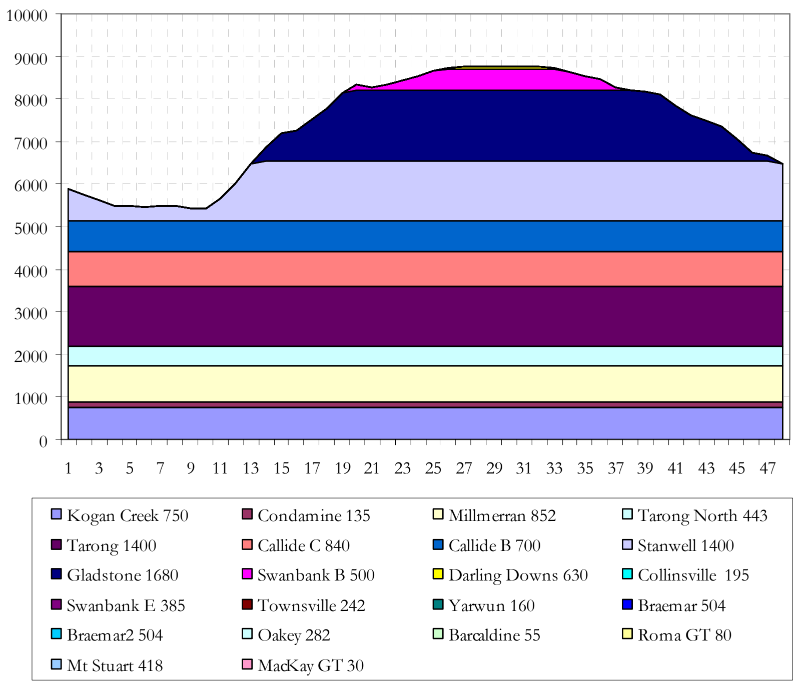
This can be illustrated as follows. Let's suppose that we have a simple electricity industry with three generators each with a capacity of 1000 MW and with a variable cost of \$10/MWh, \$20/MWH and \$30/MWh respectively. If these generators were dispatched according to the merit order (ignoring start-up costs and so on), the first generator would be dispatched up to the point where its capacity is exhausted, and then the next would be dispatched, and so on. This would result in a dispatch pattern given by the first diagram in Figure 11 below, with clear bands in the dispatch diagram. However, if generators are targeting a market share target we would find that, instead, the dispatch of each generator increases and falls in line with the overall region demand, as in the second diagram:

Figure 11: Coordination through targeting of market shares results in quite different dispatch patterns from purely competitive outcomes



We can illustrate this effect in practice. The following data illustrates the situation in the Queensland region of the NEM on 18 January 2010. If we assume that the figures published by ACIL Tasman for SRMC of generators in the NEM[26] accurately reflect these generators true costs, and taking their registered capacities, then ignoring start up costs, ramp rate constraints or other complications, according to strict merit order dispatch, these generators should have been dispatched on this day according to the pattern in Figure 12:

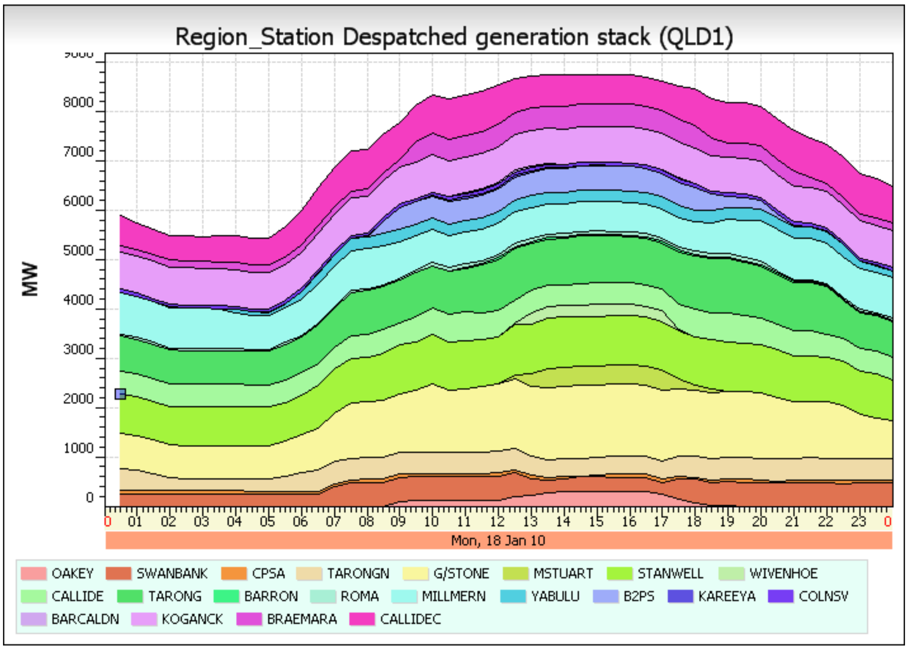
Figure 12: Hypothetical dispatch pattern for QLD 18 January 2010 if each generator was dispatched at its ACIL Tasman SRMC



In contrast, the actual dispatch of many of these generators tended to follow the total load in the region, as shown in Figure 13:

[26] ACIL Tasman (2009).

Figure 13: Actual dispatch pattern for QLD 18 January 2010



I want to be clear that I am not suggesting these graphs provide strong evidence of cooperative arrangements between generators in QLD, merely that if there were such an arrangement it might be consistent with what we observe.

In summary, the exercise of market power in electricity markets is not necessarily merely a matter of the unilateral action of a few large or rogue generators. It may also result from the coordinated action of a group of generators who have learned to co-operate with each other.

1.8 Is the exercise of market power harmful or is it necessary to stimulate investment?

Some commentators argue that if all generators simply offered their output to the market in a manner which reflected their SRMC curve, some generators would be unable to cover their fixed costs. The exercise of market power is necessary, it is argued, to ensure that the industry as a whole is able to cover its costs. Is the recovery of fixed costs incompatible with a highly-competitive market? Put another way, is the exercise of market power necessary to cover fixed costs?

It is clear that, in other markets in the economy, there is no requirement to exercise market power in order to cover fixed costs. As Borenstein and Bushnell (2000) observe:

> "There is simply no support in theory or practice for the claim that firms – even firms in capital-intensive industries – must exercise market power in order to cover their costs. … Finally economic theory does not support an argument that price must exceed the competitive level for firms to break even. In fact, under reasonable conditions, the absence of market power leads to normal returns on investment with exactly the socially optimal quantity of electricity generation capacity".[27]

Let's suppose the wholesale market were highly competitive, so that every generator offered its output in a manner which reflected its SRMC curve. In this context, generators with a lower SRMC are able to earn a contribution towards their fixed costs whenever the wholesale price increases above their variable costs, as normally occurs when generators further up the merit order being dispatched. A potential problem arises, of course, for the generators in the market with the highest variable cost. It is clear that in an energy-only market such as the NEM, the wholesale spot price must, at least at certain times, increase above the level of the variable cost of

[27] Borenstein and Bushnell (2000), page 50.

the most expensive generating unit in the market (otherwise that most-expensive unit would not be able to cover its fixed costs).

If the NEM were highly competitive there are only two ways that the wholesale spot price could increase above the variable cost of the most expensive generating unit – if the wholesale spot price was set by a demand side bid, or if there was a supply shortfall, resulting in involuntary load shedding and the wholesale spot price increasing to the price ceiling.

In practice demand side bids – although theoretically possible – are relatively rare. This is one aspect of the current market design which may need to be revisited, as discussed later in this paper. In the absence of any demand side bids, prices would spike in a highly competitive market only when there is a shortfall of supply. Rough calculations show that approximately 9-14 hours of pricing at the price ceiling per year would be required to cover the fixed costs of a high-cost peaking generator. In an energy-only market such as the NEM some price spikes are necessary if all generators are to be able to cover their fixed costs. But, provided those price spikes are allowed to occur the exercise of market power is not necessary to ensure that all generators are able to cover their fixed costs.

At this point the objection could be made that 9-14 hours of load shedding per year would be political unsustainable and that therefore this would never be allowed to happen in practice. If there were no other solutions to this problem we would be forced to conclude that the energy-only market does not allow all generators to cover their fixed costs without some degree of market power. But there are other solutions. For example, increasing the wholesale price cap will reduce the number of hours of pricing at the market price cap required to cover the cost of a peaking generator. Alternatively, purchasing reserve capacity which only enters the market when there is a shortfall of normal generation capacity will allow high prices to occur without risk of load shedding.

In summary, an energy-only market requires occasional price spikes. If there are political or administrative restrictions on prices occasionally going to very high levels then it follows that if the market were highly competitive, some generators would not be able to cover their fixed costs. On the other hand, by removing the political or administrative restraints on price spikes (perhaps by ensuring that load is not shed at times of tight supply-demand balance) there seems to be no incompatibility between high levels of competition in the market and generators covering their fixed costs.

It is important to emphasise that the exercise of market power does not imply that some generators will necessarily be earning excess returns or monopoly rents. In a situation where there is general over-capacity in the market, generators may exercise market power when there are opportunities to do so but still the overall annual average price (or, more strictly, the price-duration curve) may only be barely sufficient to allow all the existing generators to remain in the market. In this case, however, economic efficiency would say that some plant should be retired from the market as it is surplus to requirements. In this case the exercise of market power has the effect of inefficiently delaying that process of retirement of surplus capacity.

I have argued that market power is not necessary to ensure generators can cover their costs, but is market power actively harmful to the market? There are two possible ways of answering this question of harm to the market – the first is by exploring the effect of market power on competition in a related market, the second is by exploring the effect of market power on conventional measures of economic welfare.

In terms of the effect of market power on competition, in principle it would be possible for a generator with market power to have both the ability and the incentive to affect competition in a related market. For example, a generator which is also active in a retail market with a fixed retail price cap might find that it is able to squeeze its unintegrated downstream retail rivals by raising the average wholesale price for electricity. This might force some of those downstream rivals to leave the market (perhaps through bankruptcy). This might be valuable as a mechanism for developing a reputation for being tough on rivals downstream.

In terms of the effect of market power on conventional measures of economic welfare, we can separate the impact of market power into two broad categories – short-run and long-run effects. In the short-run the exercise of market power reduces the efficiency of use of the stock of existing generation assets and the efficiency of decisions as to when to make use of demand side responsiveness.

Ideally, given the stock of generation assets in the market at any given point in time, those assets should be used as efficiently as possible. This implies, amongst other things, that generators should be called on in accordance with their merit order – cheaper generators should be called on to produce, and should have their capacity exhausted, before calling on more expensive generators. One of the effects of market power is that it may give rise to out-of-merit-order dispatch. That is, lower cost generation may have its output reduced, while other, more expensive generation is called on to make up for the deficit.

For example, let's suppose a baseload generator with a variable cost of $10/MWh capable of producing, say, 2000 MW, reduces its output from, say, 1800 MW to, say, 1200 MW. Let's suppose that, as a result, a peaking generator with a cost of $210/MWh is required to turn on to make the shortfall of, say, 600 MW. This results in a social waste of 200 x 600 = $120,000 for every hour that this market power persists (not counting any start-up costs).

The AER commissioned IES to explore the magnitude of these short-run dispatch costs on a few selected days in the NEM. The cost of inefficient dispatch on these days was often in the range of $1-2 million per day, with a peak at $4.8 million (for the 18 January 2010 in QLD).[28]

Furthermore, and perhaps even more significantly, the exercise of market power may result in inefficient use of demand-side response. The exercise of market power may result in particularly high prices which may cause loads that have the incentive and ability to do so to reduce their consumption. For example, let's suppose a particular load is willing to reduce its consumption by 300 MW when the wholesale spot price reaches $5000/MWh. If a baseload generator (with a variable cost of, say, $10/MWh) reduces its output and successfully raises the wholesale spot price above $5000/MWh, inducing this load to shutdown, there is a loss in economic value equal to (5000-10)x300 or approximately $1,500,000 per hour that the exercise of market power persists.

In the longer run, the exercise of market power increases the variability and distorts the level of the wholesale price signals which has implications for hedging and for investment decisions.

Higher wholesale spot prices may also have an important impact on generator investment or retirement decisions. In particular, as noted earlier, the exercise of market power may inefficiently delay the closure of inefficient plant, or may bring forward investment in new generation capacity before it would otherwise be needed. In this case the harm from market power is the increase in the present value of the cost of the path of future generation investment due to the bringing forward of new investment or the deferment of the retirement of existing capacity.

Finally, generator market power, through its impact on the wholesale price, is likely to have at least some impact on the retail price and therefore the long-run retail demand for electricity. Even though wholesale demand for electricity is very inelastic in the short-run, in the longer run many consumers are able to switch to alternative fuels and energy sources. The exercise of market power will inefficiently induce some customers to stop consuming and/or to switch to alternative sources of fuel.

1.9 Detecting whether or not the exercise of market power has occurred

How can we tell whether or not market power has been exercised at a specific point in time in the past? In the next section we will discuss how we might predict when market power might be exercised in the future.

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[28] IES (2010).

[30] See, for example, ACIL Tasman (2009).

As discussed earlier, under the broadest definition, market power has been exercised when the generator submits an offer curve so that the generator is dispatched for a price-quantity combination which is not on its SRMC curve for other than purely technical reasons (such as start-up costs, ramp rate constraints, or so on). In principle then, the detection of market power ex post is primarily a matter of comparing the generator's offer curve (or, more strictly, its price-dispatch quantity combination) to the generator's SRMC curve.

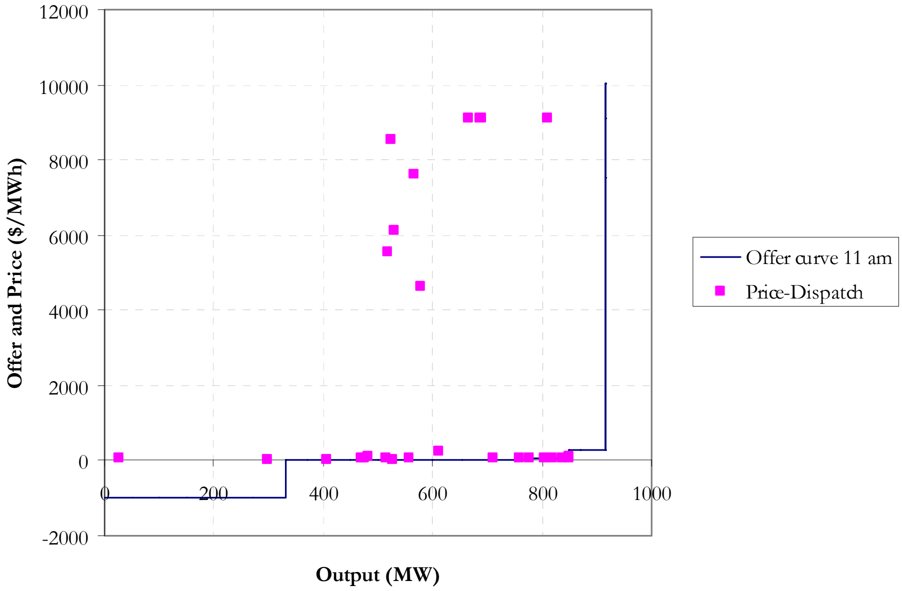
The problem is that a generator's SRMC curve at any given point in time is not normally observable. One possible approach (although this is not normally attempted) is to just use published information on the SRMC curve of different generators in the NEM. ACIL Tasman regularly publishes simple estimates of the fixed and variable costs of different generators in the NEM (excluding, of course, hydro generators).[30] If these values reflected the true capability of the respective generators the majority of the time these values could, in principle, be used to detect the exercise of market power.

The problem with this approach is that a generator's maximum output may be temporarily limited below its theoretical maximum for a number of reasons related to the physical operation of the plant which is not immediately observable to an outsider. Similarly, a generator's variable cost of operation may depend on the spot price of the input fuel (or, otherwise on the contractual arrangements for the purchasing of the input fuel) in a manner which is not observable to an outsider. The variable cost of a hydro (or energy-limited) generator depends in a complex way on the future expected water inflows and future expected prices which, again, are not typically observable by an outsider. In general there is no straightforward manner to observe the SRMC curve of a generator at a specific point in time. For this reason, studies which attempt to detect market power through a comparison of price-dispatch outcomes and estimated generator SRMC curves have generally been discredited.

Most approaches to detecting market power use some alternative SRMC proxy as a benchmark against which to compare the price-dispatch outcomes of a generator. One such approach relies on the observation that at times when the market is reasonably competitive, generators have an incentive to offer their output to the market in a manner which broadly reflects their SRMC curve (at least over a range). Under this approach, therefore, a particular time is chosen when the market is assumed to be reasonably competitive, and the generator offer curves are assumed to broadly reflect their SRMC. The price-quantity combinations of each generator at other times are then compared to this benchmark to detect the exercise of market power.

To illustrate this approach, Figure 14 illustrates the behaviour of Torrens Island Power Station on 11 January 2010. Around 11 am in the morning this power station was offering around 915 MW to the market at a price less than $300/MWh. This offer might be taken as a benchmark or indicative offer on this day. The pink dots represent the price-quantity combinations for Torrens Island later the same day. As can be seen for many half-hour intervals on this day, Torrens Island was dispatched to a quantity and paid a price well above this benchmark level. This is indicative of the exercise of market power.

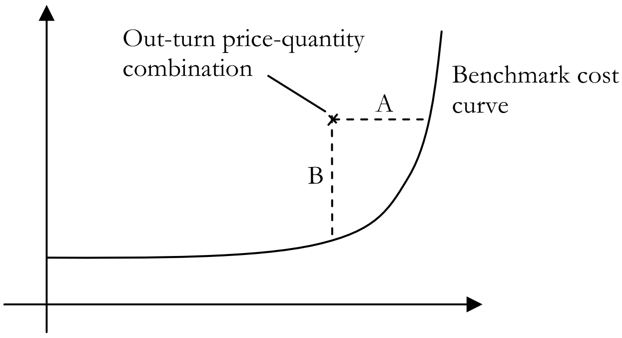
Figure 14: Benchmark offer curve and price-dispatch outcomes for Torrens Island 11 January 2010



If a price-quantity combination which departs from the benchmark cost curve has been found this is suggestive of the exercise of market power by that generator at that point in time. But several further issues remain to be resolved:

- First, there is the question as to how to quantify the departure from the benchmark cost curve – for example, should it be measured as the reduction in capacity relative to the benchmark level of capacity at that price (the distance A in Figure 15 below), or should it be measured as the distance between the out-turn price and the benchmark marginal cost at that level of output (the distance B in the diagram below)?

Figure 15: Market power can be measured as the deviation in quantity or price from the SRMC curve



- A second key issue that arises relates to the fact that the market power of a generator will typically vary significantly over time. Opportunities to exercise market power typically only arise when market conditions are favourable – such as when transmission constraints are binding, when demand is high, or when there are outages of generation or transmission plant. How should we reflect the aggregate or average level of market power of a generator over time? If a generator only has market power on average on one hour out of every one hundred hours, is that significant? If a generator has a little bit of market power for many hundreds of hours in a year is that significant? It is worth noting that a substantial increase in the wholesale price even for relatively few hours in the year will have a material impact on the annual average wholesale price. Just one hour of pricing at the market price cap adds $1.40 to the annual average price. If the annual average price is $30/MWh, even just one quarter of one per cent of hours at the price ceiling (around 21 hours) is sufficient to double the annual average price. Ideally this would be reflected in the aggregate measure of market power that we choose.

Price-cost margin studies

Many studies detect the existence of market power by measuring the bid-cost margin (that is, the distance B in the diagram above)[31], typically by computing the Lerner index – i.e., the price-marginal cost margin, defined as: $L = \frac{P - MC}{P}$. It is straightforward to show that an unhedged profit-maximising generator with market power (and facing a smooth continuous residual demand curve) should choose a level of output where the Lerner index is equal to the reciprocal of the elasticity of the residual demand curve. In other words, there is a clear theoretical link between the Lerner index and the elasticity of the residual demand curve faced by a generator. If the generator faces a highly elastic residual demand curve it should choose a level of output on or very close to its SRMC curve.

One of the problems with this approach is that as the output of a generator approaches its available capacity, the SRMC curve will usually become very steeply sloped, so the price-cost margin will be very sensitive to the precise location of the SRMC curve chosen – potentially making the indicator of market power unreliable. Twomey et al (2005) observe that: "Some studies set the price-cost margin to zero in hours where there is no spare capacity, ensuring that high prices at these times are not seen as evidence of market power". They go on:

> "Given all of these issues, even if a study uncovers a large price-cost margin, it is still difficult to say conclusively whether this is due to abuse of market power or estimation error. This was well illustrated in the highly contentious hearings to determine the refunds to utilities from suspected market power abuse by a number of generators during the California crisis, 2000-2001".[32]

Quantity-withdrawal studies

Given these problems with measuring the bid-cost margin it is often more straightforward to measure the volume of output withheld by a generator (the distance A in figure 5). This approach was introduced by Joskow and Kahn (2002) and has been advocated by Brennan (2003, 2005) amongst others. Biggar (2004, 2005) used this approach in studies of market power in the NEM. This is also the approach which will be used in the remainder of this paper. Twomey et al (2005) conclude that they "see the potential for this tool to become a standard technique of market power analysis".[33]

Other approaches

As noted earlier, physical withholding (as opposed to economic withholding) is not currently an issue in the NEM. But if measures to mitigate market power were put in place, generators might attempt to disguise their withholding as the physical outage of plant. Some studies have attempted to measure outage rates to determine if physical plant failure is more common at times when market power is likely to be present.[34]

Finally, some studies have sought to measure the extent or the impact of market power by simulating what the market outcome would-have-been but for the supposed exercise of market power. These studies inevitably make some assumptions about how generators would-have bid in the absence of market power. Typically this involves making some assumption about the SRMC

[31] Recent studies include Short and Swan (2002), Fabra and Toro (2003), and Evans and Green (2005).

[32] Twomey et al (2005), page 23.

[33] Twomey et al (2005), page 35.

[34] Joskow and Kahn (2002) find evidence of physical withholding but this has been questioned by Hogan, Harvey and Schatzi (2004).

curve of each generator. As has been emphasised above there are serious issues with attempting to estimate the SRMC curve.[35] External observers typically are unable to observe the precise plant availability on any given day, the opportunity cost for energy-limited plant, or the fuel cost for thermal plant. Failure to include start-up costs or minimum loading constraints may lead to the SRMC curve being underestimated.[36] Furthermore, these models must take into account all the features of the real market, including transmission constraints.[37] A comparison of real world outcomes with a market simulation based on all generators bidding at their estimated SRMC is not usually credible.

On the other hand there is scope for use of market simulation for determining the impact of particular episodes of market power where the bidding behaviour of all generators is held unchanged except for the bidding behaviour of the generator in question. (This was the approach used by IES also in a report prepared for the AER). In that study, the market outcomes on particular days were compared with the market outcomes on those same days assuming that the offer curve of just one or two generators is replaced for a few hours with their offer curve earlier the same day.

1.10 Forecasting the exercise of market power that might occur in the future

Even if we are able to detect whether or not market power has been exercised in the past, in many applications we would like to be able to predict whether or not market power might be exercised in the future.[38] Such analysis is needed when, for example, considering the impact of a proposed merger of generators, when considering the costs and benefits of an augmentation to the transmission system, or when carrying out simulations of likely future incentives for investment.

Traditional market share indicators

Competition policy analysts have developed a series of indicators which are typically used as rules-of-thumb to indicate when a typical market in the economy is likely to exhibit market power. These rules-of-thumb are usually based on information on the market shares of at least the largest firms in the market. These indicators include, for example, the four-firm concentration ratio (CR_4) and the Hirschmann-Herfindahl index (or HHI).

The four-firm concentration ratio is the simple sum of the market shares of the four largest firms in the market. Let's suppose the market shares of all the firms in the market (in order from largest to smallest) are given by $s_1, s_2, s_3, \ldots$ The four-firm concentration ratio is simply: $CR_4 = s_1 + s_2 + s_3 + s_4$. The higher this value the more likely (in principle) the market is to exhibit market power (either unilateral or coordinated market power).

The HHI is the sum of the squares of the market shares of all the firms in the market: $HHI = s_1^2 + s_2^2 + s_3^2 + \ldots$. The higher the HHI the more highly concentrated the market. It is straightforward to demonstrate that the HHI is theoretically directly related to the level of market

[35] Twomey et al (2005): "The chief controversy associated with this tool comes, again, from the difficulties involved in defining and estimating the marginal costs. The debate still continues as to the reliability of competitive benchmark analysis in light of such potential estimation errors".

[36] See Mansur (2007).

[37] Harvey and Hogan (2002) criticise simplistic models which attempt to model competitive outcomes ignoring key aspects of real world markets such as transmission constraints.

[38] Twomey et al (2005) is a useful survey which goes beyond the material in this section.

power in a market in which the participants are playing a "Cournot" (or "quantity") game in the absence of capacity constraints.[39]

Unfortunately these classic or traditional indicators have significant drawbacks when applied in the context of the electricity market:

- These indicators do not take into account the very low wholesale elasticity of demand for electricity. The HHI, as noted above, has some foundation in economic theory but only in the case of an industry in which the major players are interacting using a Cournot game without capacity constraints. Even then, the theory shows that the level of market power that arises in such a market is a function of both the HHI and the wholesale elasticity of demand. A given level of HHI could correspond to little or no market power in a market with moderately elastic demand but, at the same time, could correspond to a very high level of market power in a market with very low elasticity of demand. In competition policy analysis an HHI of less than 1000 is usually taken as an indication that a market is broadly competitive. But if the elasticity of demand is low enough, even an electricity market with an HHI of 1000 could give rise to significant market power.

- These indicators do not effectively take into account the fact that electricity generators face capacity constraints, so that the elasticity of the supply curve can be very low at times, especially at peak periods. For example, consider an electricity industry with one generator with ten per cent market share, and 90 other generators with one per cent market share. The four-firm concentration ratio is only 13 per cent and the HHI of this market is only 190, both of which would normally indicate a highly competitive market. Yet, at those times where the smaller generators are operating at capacity, the remaining large generator in the market could have very substantial market power. Sheffrin (2001) points out that under certain definitions of the relevant market, no single supplier in California had a 20% market share during the California crisis, yet many would argue that the market was not workably competitive.

  In an attempt to address this problem OECD (2002) proposes a variation of the standard HHI measure, referred to as the 'adjusted HHI'. The adjusted HHI takes into account the fact that at any given point in time, some fraction s_C of the stock of generators are operating at capacity and cannot expand their output to mitigate an attempt to exercise market power. If there are *m* unconstrained generators remaining the formula for the adjusted HHI is as follows:

  $$HHI^{adj} = s_1^{\ 2} + s_2^{\ 2} + s_3^{\ 2} + \ldots + s_m^{\ 2} + (1 - s_C)\frac{s_C}{m}$$

  The adjusted HHI for the simple market structure above (with one ten per cent generator and 90 one per cent generators) is 1000. Taking into account the low elasticity of demand (the first point above), this could represent a material degree of market power.

- These standard measures do not naturally or easily take into account the significant impact of transmission constraints. As already noted, transmission constraints can be thought of as limiting the geographic size of the relevant market. A simple or naïve application of the concentration ratio or HHI which ignored the presence of transmission constraints could significantly over-estimate the level of competition in the market. In principle, this problem could be partially addressed by determining the relevant geographic scope of the market for each dispatch interval. However this is computationally intensive and raises the issue of aggregation, discussed shortly.

[39] Studies of electricity markets using the HHI concept include Schmalensee and Golub (1984), Cardell, Hitt and Hogan (1997), Williams and Rosen (1999), Blumsack, Perekhodtsev and Lave (2002), and Blumsack and Lave (2004), and Fabra and Toro (2003).

- These indicators ignore the impact of hedging arrangements on the incentive to exercise market power. As we have seen, even a market with apparently very high concentration may not exhibit market power if the relevant generators are fully hedged with long-term fixed price contracts. Conversely, even an electricity market with apparently reasonable levels of concentration could exhibit substantial market power at times if the relevant generators are largely unhedged.[40]
- Finally, there is the problem that the degree of market power in an electricity market will vary from one moment to the next according to factors such as the level of demand, the presence of transmission constraints, and/or generator outages. This gives rise to a problem of how to aggregate measures of market power over time. If market power increases by a large amount in a few dispatch intervals should that be given more prominence than a minor increase in market power over a large number of dispatch intervals? Even if the indicators mentioned above were accurate in each dispatch interval (I have argued they are not), how should they be aggregated over a large number of dispatch intervals – should they simply be averaged? Or should we focus only on the number of dispatch intervals with apparently high levels of market power? There is no easy answer to these questions.

Twomey et al (2005) conclude the following:

> "Empirically there is surprisingly little evidence supporting the usefulness of market share and HHI in predicting market power in electricity markets. The California experience, where market designers relied heavily upon low market share and HHI indices to allay fears of market power, clearly demonstrates the potentially misleading nature of these metrics. Accordingly it is unlikely that these indices will be the primary tool of market power analysis but they will most likely still serve a role in the potential screening of market power in long-term ex ante studies of market design or merger proposals. Perhaps the most important point to make is that the normal EU screens for Significant Market Power used in other markets are likely to greatly underestimate the potential market power in electricity markets".[41]

The PSI and RSI

Recognition of the problems with conventional measures of market power has led to the development of a number of new measures of market power in electricity markets. These include the pivotal supplier indicator and the residual supply index.

Due to the presence of capacity constraints and transmission constraints, even quite small generators can have very significant market power if their output is required in order to balance supply and demand. For example, in the simple market structure mentioned above with one ten-per cent generator and 90 one-per cent generators, if demand exceeds 90 per cent of the installed capacity the output of the ten-per cent generator is required in order to balance supply and demand. In principle this generator could, at such times, push the wholesale spot price all the way to the wholesale spot price ceiling. Such a generator is known as a *pivotal supplier*.[42]

Putting aside issues related to transmission constraints, a generator is said to be a pivotal supplier at a given point in time if and only if the wholesale demand exceeds the capacity of all the other generators in the market at that point in time. If the wholesale demand is D_t and if the capacity of the other generators in the market is C_j, the pivotal supplier indicator for generator i is defined as follows:

[40] See, for example, Bushnell, Mansur and Saravia (2007).

[41] Twomey et al (2005), page 33.

[42] The origin of the Pivotal Supplier Indicator is shrouded in mystery. There are various citations to papers by Bushnell and others around 1999 but a check reveals those papers either don't exist or don't mention the PSI.

$$P_{it} = \begin{cases} 1, & \text{if } D_t \geq \sum_{j \neq i} C_j \\ 0, & \text{if } D_t < \sum_{j \neq i} C_j \end{cases}$$

The notion of the pivotal supplier captures some key features of the electricity market – including the fact that market power tends to be linked with high demand periods and that, at those periods, even very small generators can have very significant market power.

But certain issues with the pivotal supplier index remain. The first issue relates to the problem of aggregation noted above. If a generator is only "very slightly pivotal" (i.e., only a little bit of its capacity is needed to balance supply and demand) for many dispatch intervals, is this more serious than a situation where a generator is substantially pivotal for a few dispatch intervals? The normal practice is simply to average the pivotal supplier indicator over time. Another issue, discussed more below, is that the pivotal supplier index ignores the impact of hedging arrangements.

Another, potentially more serious problem with the pivotal supplier index is that it ignores the impact of transmission constraints. As we have seen, at least in the NEM, transmission constraints play a significant role in the exercise of market power. A generator may never be pivotal on a NEM-wide basis but may still have significant market power on occasion due to the presence of transmission constraints.

To solve this problem Hesamzadeh, Biggar and Hosseinzadeh (2011) propose a version of the pivotal supplier indicator which takes into account the effects of transmission constraints. This indicator in essence asks the question – can the energy balance constraint be satisfied at all of the relevant nodes of the network without the capacity of the generator in question, while satisfying all of the transmission constraints. If the answer is yes, the generator is not pivotal, otherwise (of course) the generator is pivotal.

One potential criticism of the pivotal supplier index is that it potentially both over-estimates and under-estimates the true extent of market power. For example, experience shows that many generators offer a small proportion of their capacity at or near the market price cap at all times. In this circumstance, a generator may find that its output is required to keep price at moderate levels even before the generator technically becomes "pivotal". If other generators are offering some of their output at a price close to the price cap, the pivotal supplier index may overlook certain episodes of genuine market power and therefore may underestimate the extent of the opportunities for market power.

On the other hand, as already emphasised, the level of hedging of a generator has a strong influence on its incentive to exercise market power. A generator which has pre-sold 50 per cent of its capacity in long-term fixed-price forward contracts has no incentive to reduce its output below 50 per cent of its capacity, even if doing so increases the wholesale spot price to the price ceiling. A generator which has pre-sold a proportion of its capacity in long-term fixed price forward contracts cannot meaningfully be said to be pivotal until demand increases to the point where some of the remaining unhedged capacity must be called on in order to balance supply and demand. Formally, a generator is strictly only pivotal if demand exceeds the sum of the capacity of other generators plus the *hedged* capacity of the generator in question. In this sense the pivotal supplier index may over-estimate the potential for market power.

As noted above, one of the problems with the pivotal supplier indicator is its binary nature – a generator either has market power or it doesn't – whereas in reality an unhedged generator might have market power when it is "almost pivotal". At the same time, a hedged generator might not have market power until it is "quite a lot pivotal". One way to address this is to use a continuous measure of the extent to which a generator's output is required in order to meet demand.

The Residual Supply Index (RSI) is the ratio of the total capacity of all the other generators in the market to the total market demand at a point in time. Formally the RSI for generator *i* at time *t* is given by:[43]

$$RSI_{it} = \frac{\sum_{j \neq i} C_j}{D_t}$$

When the RSI is greater than 1 the other generators in the market can meet market demand without the generator in question. When the RSI is less than one, the generator in question is a pivotal supplier. In principle, the lower the RSI, the greater the extent of the market power. As Twomey et al (2005) observe:

> "Empirically, the RSI has been used successfully in predicting actual market power as measured by the price-cost mark-up. CAISO analysis of actual hourly market data found a significant relationship between hourly RSI and hourly price-cost mark-up in the California market. The relationship indicates that on average an RSI of about 120% will result in a market price outcome close to the competitive benchmark".[44]

Twomey et al (2005) note that they expect the PSI and RSI to "become a standard technique in market power analysis" in electricity markets.

Residual demand analysis

There are other ways to estimate the extent of market power of a generator. One way is to directly compute the residual demand curve facing the generator. Recall that the residual demand curve is the market demand curve less the offer curves of all the other generators in the relevant market. One possible approach is to estimate the SRMC curves of the other generators, and then to estimate the residual demand curve of the generator in question, assuming that the other generators offer their output to the market in a manner that reflects their SRMC curve. The elasticity can then be computed at a particular point on the residual demand curve. This elasticity is interpreted as an index of the market power of that generator at that point in time. This approach is known as residual demand analysis.[45]

Issues still remain, however. One potentially important issue is that, in practice, generator offer curves are step functions, with an elasticity which is either zero or infinite. To implement this method it is necessary to approximate each generators' offer curve with a smooth function. Other implementation issues include how to aggregate the index over time, how to handle transmission constraints, and how to handle hedging and forward contracting.

Market simulation approaches

All of the above approaches essentially assume away some of the complexities of the market interaction between generators. Most electricity markets are best characterised as an oligopoly most of the time. Theoretically, the range of possible outcomes in an oligopoly game is large (even putting aside the possibility of repeated interaction). The possible outcomes are made even more complex by the fact that generators choose not just price or quantity strategies but their entire supply curve.

Some of the approaches above have a foundation in a particular oligopoly interaction. For example, as we have noted, the HHI approach can be derived from a simple model assuming Cournot interaction between generators with no capacity constraints. Residual demand analysis can be justified from a model of a "dominant firm with a competitive fringe". However, in

[43] See Sheffrin (2001, 2002a, 2002b) and recent work by Newbery (2009).

[44] Twomey et al (2005), page 19-20.

[45] The main empirical work employing residual demand analysis has been conducted by Frank Wolak (2001, 2003). Lee et al (2010) extend this approach to the case of transmission constraints.

practice, electricity markets can exhibit a range of different market outcomes – changing with the different demand, supply, and network conditions throughout the day.

To fully reflect the range of likely outcomes in an electricity market requires some form of market simulation exercise.[46] A number of products are available commercially which model aspects of strategic interaction within the electricity market. These models typically take as given the particular configuration of generation assets, hedge levels, network plant, and demand conditions at a point in time and attempt to find a profit-maximising equilibrium outcome (i.e., spot prices, dispatch, and flows on the transmission network).

In principle, these simulation models can more accurately estimate likely future market outcomes than simple indicators of the form discussed above. Twomey et al (2005) observe:

> "Although it is recognized that no modelling approach can precisely predict prices in oligopolistic markets, there appears to be agreement that equilibrium models are valuable for gaining insights on modes of behaviour and relative differences in efficiency, prices and other outcomes of different market structures and designs".[47]

Electricity market simulations can be divided into two categories – those that try to simulate actual behaviour through heuristic or learning approaches, and those that try to compute a theoretically-optimal equilibrium outcome.[48]

However, once again, certain issues remain:

- One issue is the definition of the range of actions available to the generators and the equilibrium sought by the model. Due to the significant computational complexity of this approach, all models limit the range of actions available to the generators.
- In those models which rely on computing a theoretical equilibrium, the most common equilibrium notion is the Nash equilibrium. But, depending on the choice of the set of allowed actions of each generator, there will typically be many possible Nash equilibria. This poses a problem for the model – if there is more than one Nash equilibrium, which one best represents likely market outcomes? Or do they all represent possible market outcomes? Should the predicted outcome of the model simply reflect the average of the full range of possible Nash equilibria? At least one of the commercially available simulation models uses the averaging approach, but this leads to puzzling outcomes, such as the possibility that price differences will arise between regions at a specific point in time, even though the transmission line between those regions is not operating at its limit. It also raises the question whether a choice of a different set of strategies would lead to a different number or range of Nash equilibria – thereby affecting the average.

  Some of the other commercially available simulation models use a different approach – they pursue an iterative approach to identify a single Nash equilibrium. But, again, this raises concerns. On what grounds should we believe that the equilibrium selected by the model reflects an outcome that will arise in the real world? Perhaps the model will systematically settle on a more competitive outcome than we would be likely to observe in the real world, or vice versa. These are complex issues which do not yet have a clear resolution.
- Furthermore, many of the issues raised above still apply. Specifically, the outcomes in these models are typically very sensitive to the hedging assumptions. How much should we assume these generators will hedge, and when. Is hedging endogenous to market

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[46] Industry Commission (1996) carried out an early simulation of the NEM. Simulation studies have also been carried out by Borenstein and Bushnell (1999) and others.

[47] Twomey et al (2005), page 30.

[48] Banal-Estanol and Micola (2010) survey the behavioural approaches to simulating wholesale electricity markets.

power, as discussed above? Finally, there remains the question of aggregation. What measure should we use to aggregate over multiple time periods?

There is one more concern with the use of commercial market simulation models which perhaps should be noted. These models are almost always proprietary – meaning that they are inevitably something of a "black box" to outsiders. In a market as complex as the NEM there is always a chance that a market outcome predicted by these models might be due to a quirk of the modelling exercise itself rather than something fundamental. It is impossible to be sure that a particular outcome is robust without the opportunity to fully test the prediction of the model under a wide range of scenarios. Even when a modeller is fully aware of the construction of the model and all the inputs that have been used, these models will sometimes predict outcomes which more closely reflect idiosyncratic features of the model than of the real world. It is much harder to detect such outcomes when the model is essentially a black box and running the model repeatedly consumes resources and computational time. It is hard for policy-makers to know how much weight they should put on the output of a model which is essentially a black box. Should they be expected merely to trust the expertise of the modellers?

Twomey et al (2005) summarise their position with respect to oligopoly simulation models as follows:

> "Their flexibility in accounting for a number of factors known to influence market power, including demand elasticity, forward contracting and transmission constraints, are their chief attractive feature. However, the large number of assumptions necessary to build these models means that the results of such analysis, while certainly interesting and indicative of certain market power conclusions are almost always open to dispute. Nevertheless we see these models, which are becoming increasingly sophisticated, as continuing to be employed in long-term ex ante market power analysis".[49]

As this section has highlighted, there are many potential indicators of market power that analysts might use. As a general principle, those indicators of market power which are used in competition policy more generally (such as concentration ratios or HHI) have certain clear drawbacks when applied in the context of electricity markets. Indicators such as the pivotal supplier indicator capture some of the key features of market power in electricity markets and are relatively simple to compute and can be useful if used with care. Market simulation exercises are probably the most reliable indicator but are computationally intensive and typically something of a black box. These latter approaches – the pivotal supplier indicator, the residual supplier index and market simulation techniques – will typically only detect the presence of unilateral market power. As already noted, electricity markets may be susceptible to coordinated arrangements. The conventional competition policy indicators – concentration ratios and HHI – may be better at picking up the scope for a market to exhibit coordinated market power.

1.11 How is market power controlled in liberalised electricity markets overseas?

The NEM is relatively unusual in that it has relatively few explicit controls on the exercise of market power. Most other liberalised electricity markets have some sort of mechanism for addressing generator market power.[50] This section highlights some of those rules in other liberalised electricity markets overseas.

Let's consider first the market rules in Alberta, Canada. The Albertan Electric Utilities Act requires that "Market participants are to conduct themselves in a manner that supports the fair, efficient and openly competitive operation of the market". A 2009 Regulation goes to some length to define what constitutes fair, efficient and openly competitive operation (excerpted below). Note that these rules explicitly address economic withholding of supply and/or manipulating supply in order to increase congestion:

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[49] Twomey et al (2005), page 36. Smeers (2004) also expresses some scepticism.

[50] This section draws on the survey prepared for the EISG, EISG (2010).

"2. Conduct by a market participant that does not support the fair, efficient and openly competitive operation of the market includes the following:

…

(d) misrepresenting to the market or to any other person the availability of electricity, electric energy, electricity services or ancillary services;

(e) misrepresenting the capability or operational status of a generating unit, transmission facility or electric distribution system to the market or to any other person;

(f) not offering to the power pool all electric energy from a generating unit that is capable of operating, except where

(i) the electric energy is used on property for the market participant's own use,

(ii) the electric energy has been accepted by the ISO for the provision of ancillary services, or

(iii) the *Electric Utilities Act*, its regulations or the ISO does not require the electric energy to be offered;

…

(h) restricting or preventing competition, a competitive response or market entry by another person, including

(i) a market participant directly or indirectly colluding, conspiring, combining, agreeing or arranging with another market participant to restrict or prevent competition, and

(ii) a market participant engaging in predatory pricing or any other form of predatory conduct;

(i) offering electric energy from a generating unit or operating a generating unit, transmission facility or electric distribution system for the purpose of

(i) creating or increasing congestion, and

(ii) being paid to relieve that congestion;

(j) manipulating market prices, including any price index, away from a competitive market outcome;"

Similar rules apply in Texas. The ERCOT market sets out the following list of prohibited activities:

"(g) Prohibited activities. Any act or practice of a market participant that materially and adversely affects the reliability of the regional electric network or the proper accounting for the production and delivery of electricity among market participants is considered a "prohibited activity." … The term "prohibited activity" includes, but is not limited to, the following acts and practices that have been found to cause prices that are not reflective of competitive market forces or to adversely affect the reliability of the electric network:

(1) A market participant shall not schedule, operate, or dispatch its generating units in a way that creates artificial congestion.

…

(6) A market participant shall not collude with other market participants to manipulate the price or supply of power, allocate territories, customers or products, or otherwise unlawfully restrain competition. This provision should

be interpreted in accordance with federal and state antitrust statutes and judicially-developed standards under such statutes regarding collusion.

(7) 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."[51]

Market power abuses are defined by Rule 25.504 as follows:

> "Market power abuses. Practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition, including practices that tie unregulated products or services to regulated products or services or unreasonably discriminate in the provision of regulated services. Market power abuses include predatory pricing, withholding of production, precluding entry, and collusion. …
>
> Withholding of production. Prices offered by a generation entity with market power may be a factor in determining whether the entity has withheld production. A generation entity with market power that prices its services substantially above its marginal cost may be found to be withholding production; offering prices that are not substantially above marginal cost does not constitute withholding of production."

Generators with less than 5 per cent of installed capacity are exempt from these requirements. If the Public Utility Commission of Texas discovers a violation of these rules, the Commission may require remediation by ordering the construction of additional transmission or distribution facilities, by seeking an injunction or civil penalties, by imposing an administrative penalty or by suspending, revoking, or amending a certificate of registration. The maximum administrative penalty that can be imposed is $25,000 per violation per day that the violation continues.

In New England, the market rules require the Internal Market Monitor to investigate the reasons for bidding behaviour by generators deemed to be a "pivotal supplier" when those bids fall outside a threshold. A generator is said to be a pivotal supplier at a given time if its aggregate energy supply offers at that time exceed the Supply Margin. The market monitor is required to investigate the offers of pivotal suppliers above $25/MWh which exceed either 300 per cent of $100/MWh above the reference level.

In the Philippines, the Electric Power Industry Reform Act of 2001, Rule 11, section 8, prohibits any conduct which restricts competition or constitutes abuse of market power or an attempted monopolization of any market for electricity i.e., price fixing, fixing output, collusion, physical or economic withholding …".

Back in Australia, the Western Australia Wholesale Electricity Market (WEM) explicitly requires that generators must submit an offer which reflects its SRMC. Clause 6.6.3 of the Wholesale Electricity Market Amending Rules (December 2006) states:

> "6.6.3. A Market Generator must not, for any Trading Interval, offer prices within its Portfolio Supply Curve that do not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity when such behaviour relates to market power."

Even where abuse of market power is not specifically prohibited an entity may be charged with monitoring market outcomes with a view to detecting the exercise of market power. In Ontario, for example, the Ontario Energy Board is required to establish a Market Surveillance Panel which is required to: "Monitor, evaluate and analyse activities related to the IESO administered markets and the conduct of market participants with a view to: (a) identifying inappropriate or anomalous market conduct by a market participant, including unilateral or interdependent behaviour

[51] Rule 25.503 http://www.puc.state.tx.us/rules/subrules/electric/25.503/25.503.doc

resulting in gaming or in abuses or possible abuses of market power; … and (e) recommending remedial actions to mitigate the conduct, flaws and inefficiencies referred to in (a)".[52]

Many overseas markets also have explicit rules addressing localised market power associated with transmission congestion. For example, the IESO (Ontario, Canada) has a 3-pronged test for local market power which, if satisfied, may trigger a reduction in the price or in the congestion payments made to generators with local market power.[53] Many markets include special provisions for "Reliability Must Run" generators – that is, generators with substantial local market power. For example, in ERCOT generators designated as Reliability Must Run must enter into contracts to provide Reliability Must Run Service under which these generators are remunerated for providing these services at cost-based rates.

Frank Wolak has argued that all liberalised electricity markets must have such mechanisms for mitigating local market power:

> "In all bid-based electricity markets a local market power mitigation mechanism is necessary to limit the bids a supplier submits when it faces insufficient competition to serve a local energy need. A local market power mitigation mechanism is a pre-specified administrative procedure … that determines: (1) when a supplier has local market power worthy of mitigation, (2) what the mitigated supplier will be paid, and (3) how the amount the supplier is paid will impact the payments received by the other market participants. It is increasingly clear to regulators around the world, particularly those that operate market using locational marginal pricing, that formal regulatory mechanisms are necessary to deal with the problem of insufficient competition to serve local energy needs".[54]

In contrast, the NEM has relatively few, if any, mechanisms for limiting of mitigating the effects of the exercise of market power. The mechanisms in the NEM which could be argued to mitigate market power are the following:

- The wholesale spot price ceiling. By international standards the NEM has a relatively high wholesale spot ceiling, but it still has a ceiling. If the wholesale spot price ceiling were increased, some generators in the NEM would have stronger incentives to exercise market power – that is would tend to exercise market power more frequently, for a longer duration, and would withhold more capacity during episodes of market power. In the absence of a wholesale spot price cap many generators in the NEM would have a significantly greater degree of market power. Therefore the wholesale spot price cap can be said to be a mechanism which has the effect of limiting generator market power.
- The Cumulative Price Threshold. As discussed earlier, the NEM also has a mechanism which limits the average price over seven consecutive 24-hour periods to around \$540/MWh. Once this price threshold has been reached an Administered Price Cap applies, which in the last few years has been set at \$300/MWh[55]. This mechanism limits the extent to which a generator can exploit market power in a single region. However at present, the way this mechanism is designed, it also limits the extent to which prices can spike to signal genuine shortages of supply – which are necessary to signal the need for

[52] Article 4.1.1 of OEB By law #3. See also http://www.oeb.gov.on.ca/OEB/Industry/About+the+OEB/Electricity+Market+Surveillance

[53] http://www.ieso.ca/imoweb/marketSurveil/lmpm.asp

[54] Wolak (2005), page 17. For a more sceptical view see Ruff (2002).

[55] National Electricity Rules clause 3.14.2. The Texas ERCOT market has a similar mechanism known as the Scarcity Pricing Mechanism which operates over a much longer period (one year) and limits the sum of the positive differences between the spot price and the estimated variable cost of a peaking generator with a specified heat rate. If this margin exceeds \$175,000 per MW over an annual cycle, the cap on generator offers is set at a lower level (\$500 per MWh or 50 times the price of natural gas sold in the Houston Ship Channel on the previous day). See Schubert et al (2006).

new investment. A slightly better approach would be to simply limit the offers of generators to under $300/MWh. This would limit the market power of generators while allowing the price to increase to the wholesale price ceiling (due to demand side bids or load shedding) allowing prices to continue their role in signalling a tight supply-demand balance.[56]

- Limitations on re-bidding. Under the current market rules, generators must submit their offers and any changes to their offers (i.e., re-bids) in "good faith".[57] In practice, this means that generators cannot change their offers from those submitted a day ahead unless there has been a material change in the market. It is not clear that this requirement limits the extent to which generators exercise market power at all.

1.12 Conclusion

Electricity markets are prone to the exercise of market power. Generators exercise market power in their choice of the offer curve they submit to the market. Typically generators with market power will submit an offer curve which results in dispatch to a price-quantity combination which is well above their SRMC curve. This can usually be detected through comparison of the price-dispatch outcomes of the generator to some proxy of its SRMC curve – such as the generator's offer curve from earlier the same day.

But, at the same time, the incentives to exercise market power are complex and depend on the presence of transmission constraints, hedge levels (which may themselves interact with market power), and the scope for coordinated or collusive arrangements between generators.

On the basis of conventional competition measures the NEM market should be – at least most of the time – reasonably competitive. No generator has more than around 11 per cent share of the total capacity of the NEM. No generator in SA has more than a 3 per cent share of the total capacity of the NEM. By conventional competition law standards a 3 per cent generator should not be able to exercise market power. Yet, these conventional competition measures are unreliable in the context of the electricity market, as the next chapter shows.

[56] The proposal of the Major Energy Users limits the offer curves of certain designated generators under a broader set of conditions. See Rothkopf (2002).

[57] National Electricity Rules, clause 3.8.22A.

CHAPTER 2: THE EXERCISE OF MARKET POWER IN THE SOUTH AUSTRALIAN REGION OF THE NEM

2.1 Introduction

This chapter seeks to describe, analyse, and explain the patterns of the exercise of market power observed in the South Australia region of the NEM in the period 1 January 2008 – 31 March 2010.

During this period market power in the South Australian region of the NEM has been regularly exercised by AGL, through its control over the Torrens Island Power Station (TIPS). Specifically, at times of high demand in SA, AGL has on several occasions offered a large proportion of the available capacity of Torrens Island at a price close to the wholesale spot price cap. This bidding behaviour appears to have a significant impact on the wholesale spot price in SA.

At times of high demand in SA, TIPS, which is the largest generating station in SA, is a "pivotal generator" in the sense that, in the absence of the output of TIPS, the system operator would be unable to balance supply and demand in the SA region. In the period in question there was some additional investment in generation capacity in the SA region. However, at the same time, there has been strong growth in demand and some reduction in interconnector import capability. The market power of TIPS was not significantly eroded by new entry during this period.

The incentive on AGL to exercise market power in this way depends on the net position of AGL in the hedge markets and the nature and volume of its retail obligations. It is important to be able to understand the factors which influence the hedging decisions of generators with market power. This is discussed further below.

2.2 The exercise of market power and the impact of market price caps

This chapter is primarily about the detection of market power ex post. In the light of the discussion in section 1.9 above, this paper focuses on detecting economic withholding through a measure of quantity withdrawal. Specifically, for the purposes of this chapter a generating station will be said to exercise market power on a particular date and time if and only if:

(a) the station temporarily reduces the amount of capacity it offers to the market at a moderate price (we will define shortly what we might mean by a moderate price); and

(b) that withdrawal of capacity increases the wholesale spot market price in the region; and

(c) there is no apparent legitimate technological excuse or reason for the temporary withdrawal of capacity.

Put another way, a generator is not exercising market power if there is no reduction in the capacity it offers to the market at a moderate price, or if it has a legitimate, verifiable technological reason for temporarily reducing the capacity it offers to the market, or if its reduction in capacity offered to the market at a moderate price has no impact on the wholesale spot market price.

For the purposes of this chapter I will normally use the following thresholds. I will say that a generator is attempting to exercise market power if it temporarily reduces the amount of capacity that it offers to the market at a price less than $9000/MWh by more than 50 MW without apparent legitimate excuse.

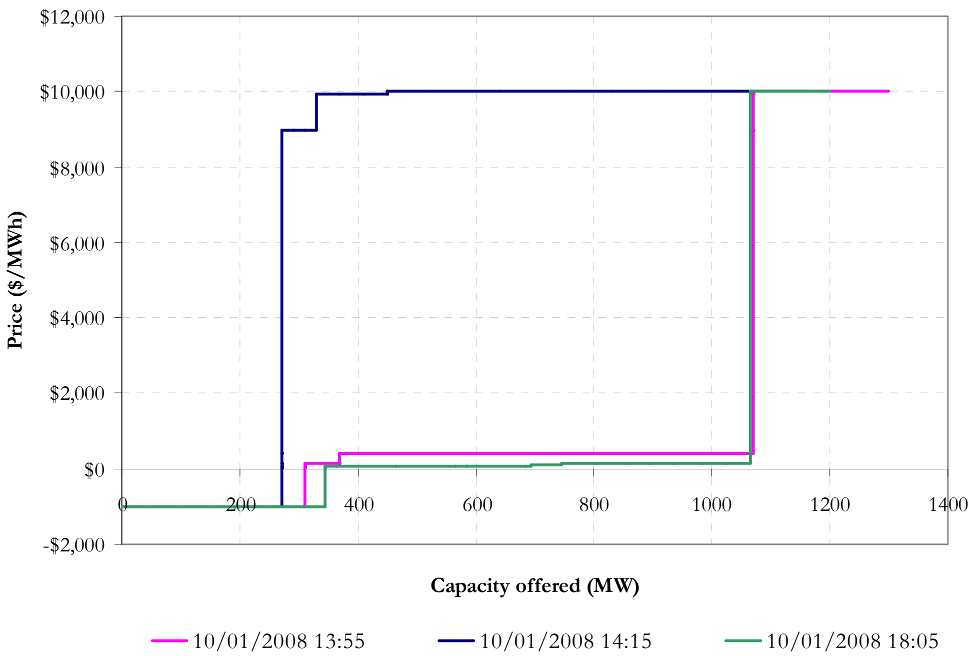
2.3 TIPS and the exercise of market power in SA

Torrens Island Power Station is located on Torrens Island in South Australia, relatively close to Adelaide. It consists of 8 natural-gas powered steam turbines. With 1280 MW of registered capacity, it is the largest power station in SA and is the single largest user of natural gas in Australia[58]. TIPS uses relatively old technology and, despite have lower carbon emissions than many other large power stations in the NEM, has higher costs and lower capacity factor.

Torrens Island Power Station was acquired by AGL Energy in July 2007. In November 2009 AGL announced that it planned a major expansion of the Torrens Island Power Station with the addition of 700 MW of peaking capacity (in the form of two large or four smaller new-generation gas turbines).[59] Construction is expected to begin in 2012.

Starting around 1 January 2008, shortly after AGL acquired control of TIPS, TIPS has, on several occasions, exercised market power by temporarily pricing a sizeable volume of its capacity at a price above $9000/MWh. To illustrate, Figure 16 below shows the offer curve of TIPS at three different times on 10 January 2008. As can be seen, on this day, up until around 2 pm, TIPS was offering around 1070 MW at a price less than $400/MWh. However, starting around 2 pm TIPS repriced much of that capacity to a very high price. From 2 pm only 270 MW was priced at less than $400/MWh. This continued until 5:30 pm, at which point TIPS offered 1060 MW at a price of less than $400/MWh. On this day the wholesale spot price for the SA region reached $9999.72/MWh in the trading interval ending 2:30 pm and stayed at that level until 5:30 pm (3 hours of prices near the market price cap).

Figure 16: The TIPS offer curve 10 January 2008 1:55 pm, 2:15 pm and 6:05 pm.



Similar behaviour has arisen on many other days during the period of this study. I will focus on those episodes in the period 1 January 2008 – 31 March 2010 during which TIPS temporarily offered more than 50 MW of capacity to the market at a price of more than $9000/MWh without apparent technical excuse. Using this definition, Torrens Island Power Station appears to have attempted to exercise market power on 35 separate days during the period 4 January 2008[60] – 31 March 2010. The full list of such episodes appears below:

[58] Source: Wikipedia.

[59] http://www.agl.com.au/about/EnergySources/indevelopment/Pages/TorrensIslandEnergyPark.aspx

[60] The period 1-3 January 2008 is excluded as TIPS was persistently offering a large proportion of its capacity at greater than $9000/MWh during this period.

Table 1: List of episodes of market power in SA 4 January 2008 - 31 March 2010

Trading day	Time of peak price	SA demand	Capacity offered above $9000/MWh	Peak price
04-Jan-08	3:30 PM	2538.62	735	$9,950.4
10-Jan-08	5:30 PM	2915.64	830	$9,999.7
18-Jan-08	1:30 PM	2047.33	560	$100.6
04-Feb-08	2:30 PM	2274.88	250	$1,543.6
18-Feb-08	6:00 PM	2896.91	820	$9,999.7
19-Feb-08	2:00 PM	2713.99	820	$8,999.7
05-Mar-08	4:00 PM	2679.21	720	$9,975.2
06-Mar-08	4:00 PM	2740.08	810	$9,950.8
12-Mar-08	6:00 PM	2915.19	740	$9,999.7
13-Mar-08	5:30 PM	2934.76	1000	$9,999.7
13-Jan-09	4:30 PM	2732.64	820	$9,999.1
14-Jan-09	3:30 PM	2314.66	60	$95.3
19-Jan-09	4:00 PM	2631.25	420	$9,999.8
20-Jan-09	3:00 PM	2462.78	350	$284.1
28-Jan-09	5:00 PM	3317.76	826	$9,999.8
29-Jan-09	2:00 PM	3250.89	170	$9,999.9
26-Feb-09	3:30 PM	2557.37	638	$222.9
29-Oct-09	5:00 PM	2106.97	280	$1,706.3
30-Oct-09	1:30 PM	2082.34	145	$111.2
02-Nov-09	2:00 PM	2341.94	360	$9,999.7
10-Nov-09	4:30 PM	2901.22	700	$9,999.8
11-Nov-09	5:00 PM	2975.58	700	$9,999.8
12-Nov-09	5:00 PM	2830.03	700	$9,999.8
13-Nov-09	4:30 PM	2857.63	675	$9,999.8
18-Nov-09	4:00 PM	2599.77	670	$44.94
19-Nov-09	5:00 PM	2992.19	670	$9,999.8
16-Dec-09	4:00 PM	2835.08	430	$297.4
08-Jan-10	4:30 PM	2794.21	515	$9,999.7
11-Jan-10	4:00 PM	3085.31	375	$9,115.6
02-Feb-10	4:30 PM	2405.39	125	$3,322.1
08-Feb-10	4:00 PM	2961.73	230	$8,430.8
09-Feb-10	4:30 PM	3108.71	340	$9,999.9
10-Feb-10	2:30 PM	2917.87	270	$8,823.8
19-Feb-10	3:30 PM	2540.17	410	$91.8
20-Feb-10	4:00 PM	2207.99	500	$165.6
26-Feb-10	6:00 PM	2357.00	415	$132.0

The following diagrams illustrate the bidding behaviour of TIPS on three of these days – with one day selected from 2008, 2009 and 2010, respectively. Figure 17 shows the bidding and dispatch of TIPS on the day highlighted above: 10 January 2008. On these charts, the orange region is the volume offered at a price below zero. The blue, light blue and green regions are the volume offered at a moderate price (less than $500/MWh). The pink region is the volume offered at a price larger than $9000/MWh.

Figure 17: Exercise of Market Power by TIPS on 10 January 2008

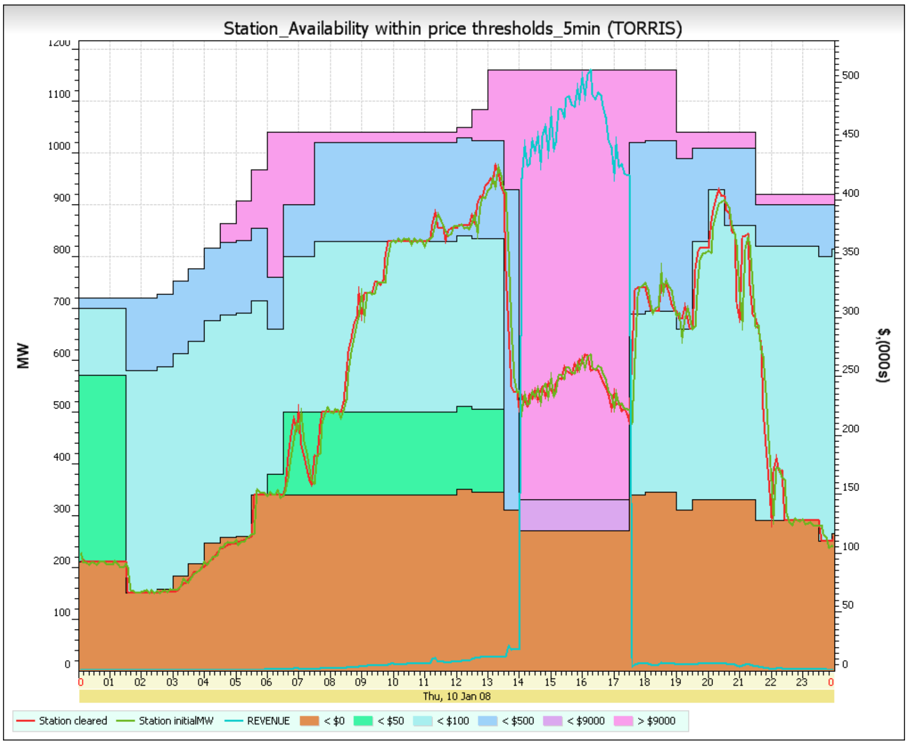


Figure 18 shows the bidding and dispatch of TIPS on 19 January 2009. Again, this is a day when the SA wholesale spot price reached $9999.77/MWh and remained above $8500/MWh from 1:30 pm until 4 pm).

Figure 18: Exercise of Market Power by TIPS on 19 January 2009

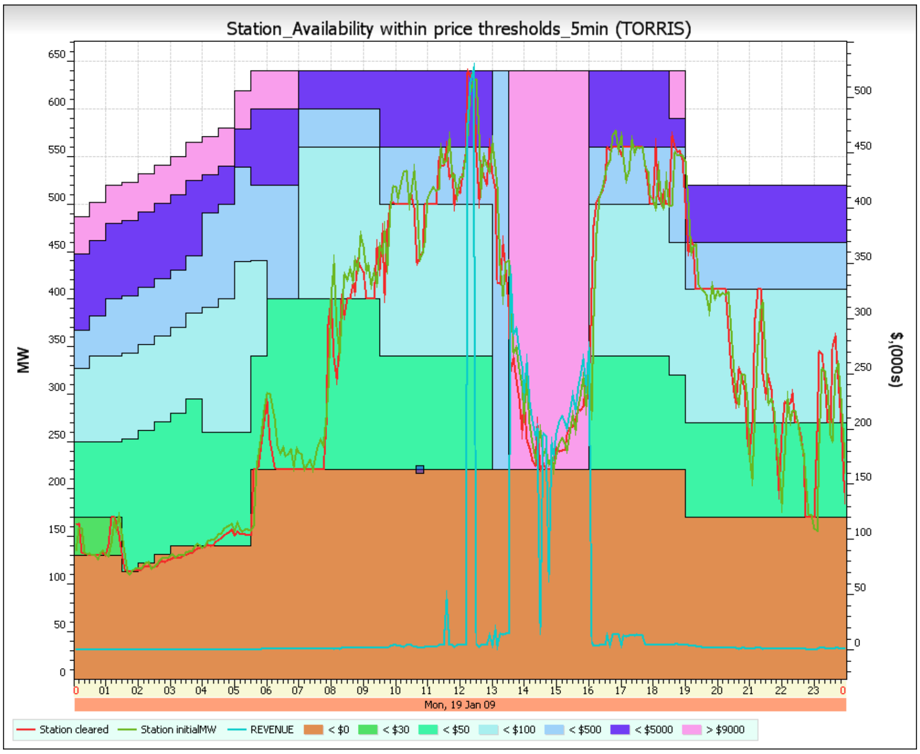
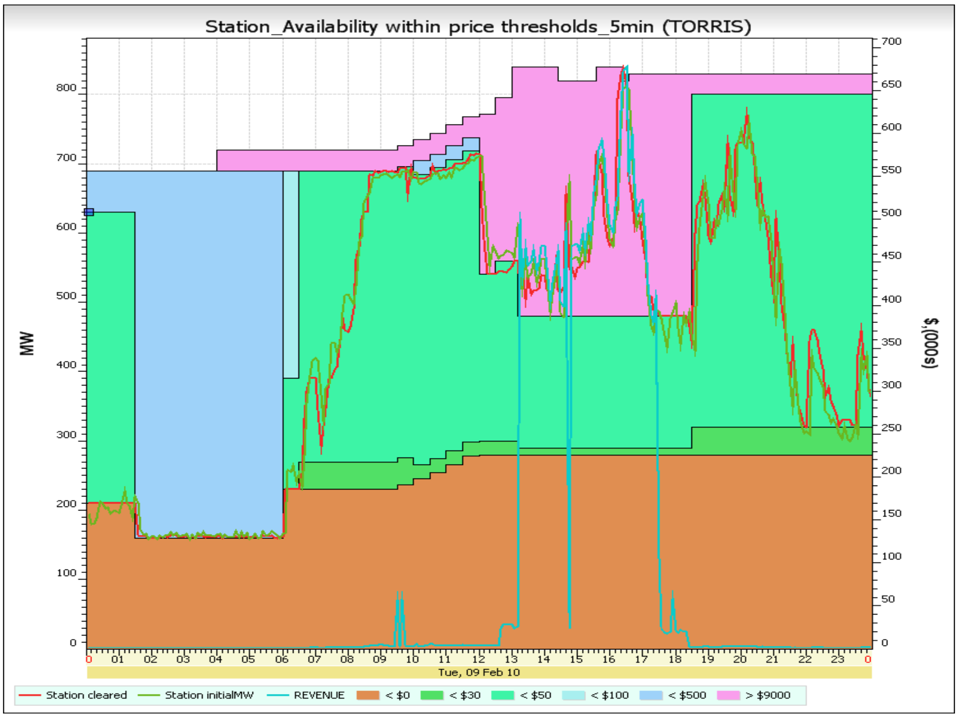


Figure 19 shows the bidding and dispatch of TIPS on 9 February 2010. On this day the SA wholesale spot price peaked at $9999.92/MWh and remained above $8400/MWh from 1:30 pm until 5:30 pm.

Figure 19: Exercise of Market Power by TIPS on 9 February 2010



As noted above, it is theoretically possible that some of these episodes were due to some legitimate forced (i.e., unintentional) change in the production capabilities of the TIPS plant. However, the temporary nature of these episodes, the fact that they coincide with periods of high demand during the day, and the fact that this behaviour is repeated on subsequent days makes this explanation unlikely, at least for the majority of these episodes. In the interim – until such times as further information emerges as to a possible legitimate technological excuse for this behaviour, I will label these episodes as episodes of market power.

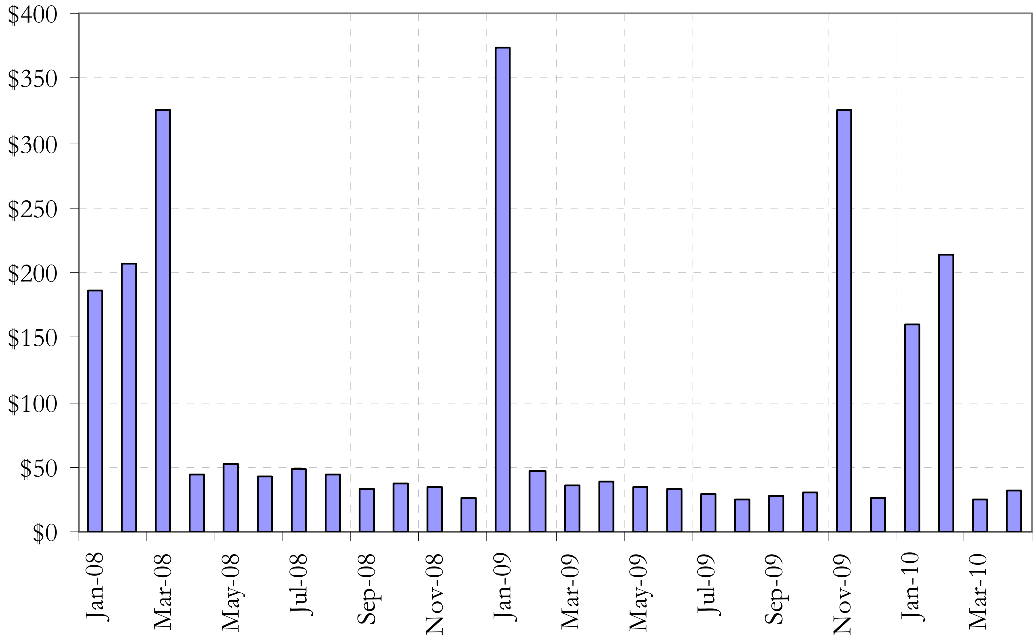
This exercise of market power seems to primarily occur on days of high demand in the NEM. There is a discussion below on the extent of correlation between days of high demand and the exercise of market power, and the extent to which TIPS is a "pivotal" generator.

First, however, we will examine the impact of this exercise of market power on the wholesale spot price in South Australia.

2.4 The impact on the SA wholesale spot price

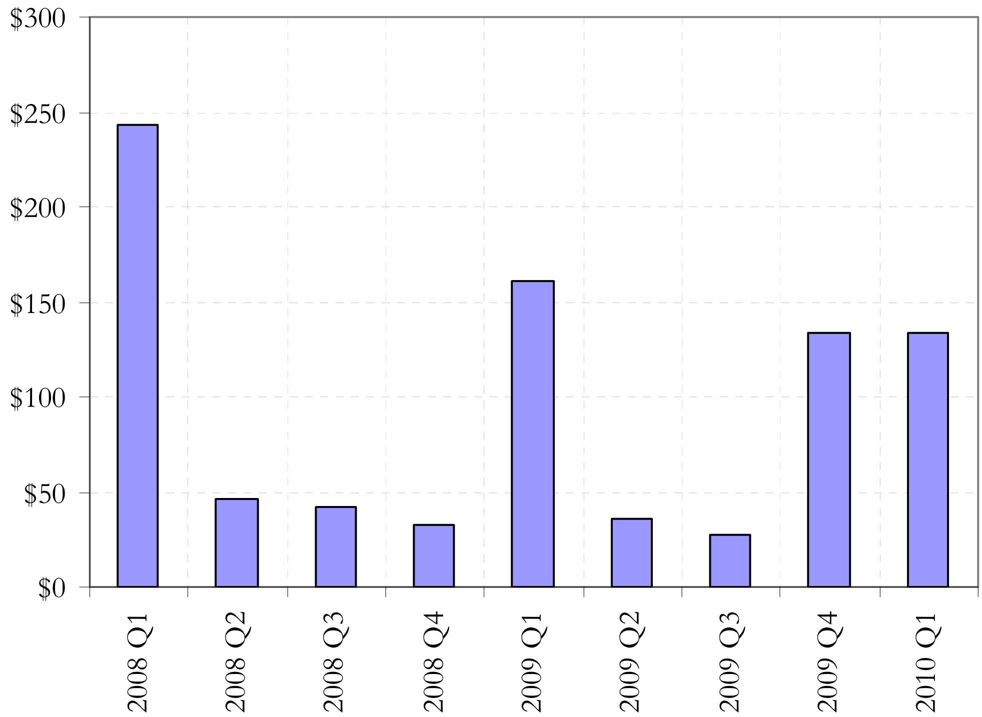
The exercise of market power on the days noted above seems to have had a material impact on the volume-weighted average wholesale price in the South Australian region. Figure 20 shows the monthly volume-weighted average (VWA) price for the SA region for the period of this study. As can be seen, in most months the VWA is between $35/MWh and $45/MWh. However, in those months in which there are episodes of market power as noted in the table above, the VWA price is five to ten times higher.

Figure 20: Monthly VWA price (SA region)



The same result is apparent when we look at quarterly volume-weighted average prices. In those months in which there are episodes of market power the wholesale average spot price is much higher than in other months.

Figure 21: Quarterly VWA price (SA)



The graphs in Figure 20 and Figure 21 are suggestive that this market power may be having an impact on the average wholesale price in SA, but they are not definitive – the price may have been high even without the exercise of market power. In order to determine what the price would have been but for the exercise of market power we must engage in some sort of counterfactual modelling, which is the exercise we turn to now.

Modelling of the counterfactual price

As just noted, it is possible that the price would have been high even without the exercise of market power. It is also theoretically possible that the dispatch of TIPS might not be affected by the exercise of market power. In order to gain some insight into the economic impact of the exercise of market power we must understand what would have happened in the absence of the bidding behaviour noted above.

Modelling what might have happened in the market if something different occurred introduces a new set of modelling issues. Some market outcomes are probably the result of strategic interaction between different generators or loads. Changing one element of that strategic interaction might result in a change in the behaviour of other players in this economic game. For example, if a change in the bidding behaviour of TIPS resulted in lower prices, some demand side responsiveness may not have occurred – raising apparent demand in the region. Alternatively, a change in the bidding behaviour of TIPS – if it had been forecast the day ahead - might have resulted in some peaking plant deciding not to incur start-up costs and therefore producing less during the day. Any change in one aspect of the market may, in principle, have an impact on the behaviour of other market participants.

Nevertheless, as a "first pass" to tackling this question we can simply assume that the response of other generators and loads to changes in market outcomes is entirely summarised in their bid or offer curve. We will change only the bidding behaviour of AGL, holding the bids and offers of other generators fixed, exploring the resulting pricing and dispatch outcomes.

Obviously, to determine the pricing and dispatch outcomes arising from a different set of bids and offers requires some sort of model of the dispatch process. The ideal approach would be to re-run the dispatch engine. This would, in principle, allow for full analysis of the effects of different constraints and losses, including intra-regional constraints. This analysis was, in fact carried out by IES in work commissioned by the AER.[61] However, for the purposes of this chapter I have relied on a simple spreadsheet supply-and-demand analysis for the SA region. This analysis ignores losses, intra-regional constraints and effects arising in other parts of the NEM. However, as we will see below, this analysis closely approximates the actual market outcomes for many of the days in question.

Specifically, the analysis below constructs an SA-region supply curve for each half-hour region on the specified day(s). A proxy for the SA region price was found by finding the intersection of this supply curve with the SA-region demand (local production less imports). Then, it was assumed that AGL would, instead of exercising market power by pricing a large proportion of its capacity at the market price cap, maintain the same supply curve as it used at a time earlier in the day. For example, in the case of the 10th of January 2008 it was assumed that AGL used the same offer curve from 12:30-7:00 pm as it offered at 12:00 noon. In other words, it was assumed that AGL simply maintained the same offer throughout the peak of the day, rather than engaging in economic withholding.

The results of this analysis for the 10th of January 2008 are shown below in Figure 22. The dark blue line shows the actual SA wholesale spot price on that day. The pink and green lines show the price resulting from this modelling exercise. The pink line shows the price arising in the model using the bids and offers as they were in the market at the time. The green line shows the price arising in the model with the offer curve for TIPS between 12:30 pm and 7:00 pm replaced with the TIPS offer curve for 12:00 noon. (Note that the vertical axis uses a logarithmic scale).

---

[61] See IES (2010). There remain issues with re-running the dispatch engine for this sort of counterfactual analysis. For example, some constraint equations depend on SCADA data as an input to the "right hand side" limit, which would potentially be different in a counterfactual run. In addition, ramp rate constraints may limit the extent to which generators could depart from their dispatch in the actual production run, so ramp rate constraints may need to be relaxed (which may introduce its own issues).

As can be seen, in the absence of the exercise of market power on this day the wholesale spot price would have been much lower – in the vicinity of $55/MWh compared to $10,000/MWh.

Figure 22: Modelling of the counterfactual price outcomes on 10 January 2008

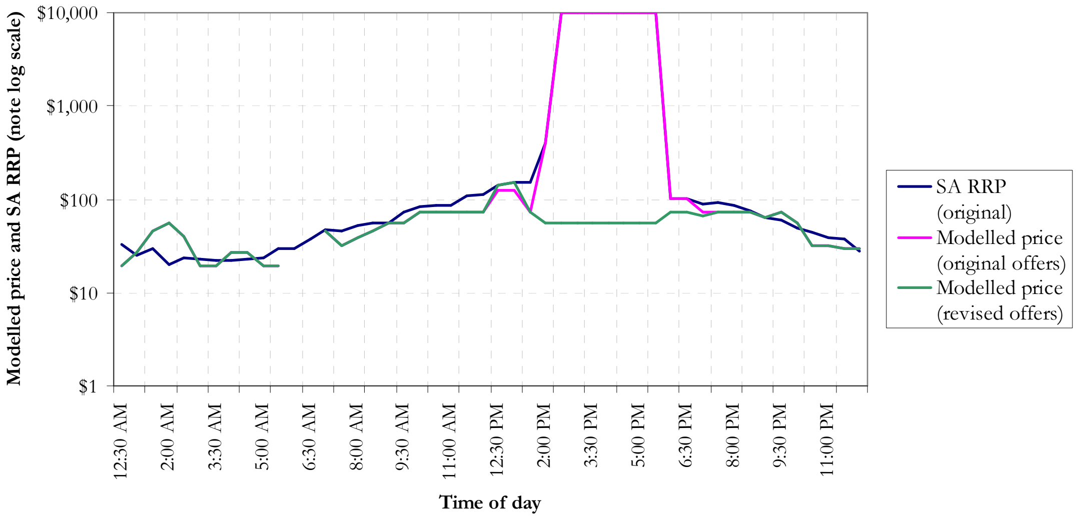
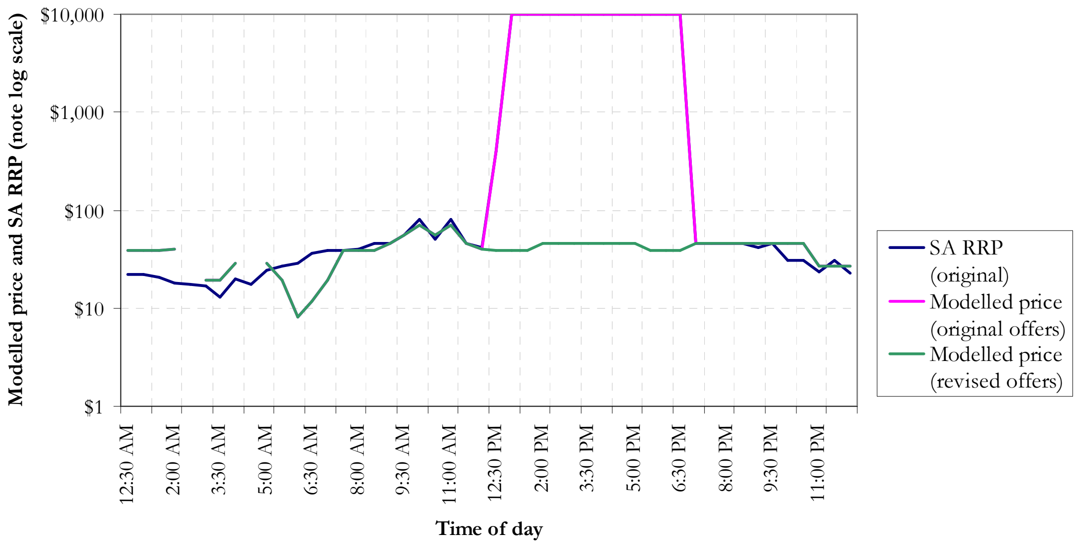


Figure 23 shows the results of repeating this exercise on one other day in summer 2008. Again we find that simply replacing the offer curves for the period 12 noon – 6:30 pm with the offer curve at 11:30 am significantly reduces the price that emerged in SA on the day (from close to the market price cap of $10,000/MWh to $38-$45/MWh). Recall that this analysis only models a single region. It is possible that, in the absence of the exercise of market power in the SA region, the SA regional reference price would have been determined by the offer of a generator outside the SA region, such as in VIC. However, answering this question would require a full modelling of the NEM of the kind carried out by IES.

Figure 23: Modelling of the counterfactual price outcomes on 18 February 2008



Both of these episodes of market power had a substantial impact on the longer-term average prices in SA. If we replace the actual prices that arose on this day with the prices emerging from the model above just for the period 2:00 pm- 6:00 pm we find that the volume-weighted average (VWA) price for January 2008 drops from $186.3/MWh to $99.5/MWh. Similarly, if we replace the actual prices with the modelled prices above for just the one day in February modelled above, the VWA for February 2008 drops from $206.6/MWh to $48.8/MWh.

Together, just these two episodes increased the VWA for the quarter from $165.8 to $213.8 (an increase of 46.4%). Finally, in the same way, just these two episodes of market power increased the VWA price for the entire 2008 calendar year from $72.9 to $92.8.

In other words, just these two episodes of market power increased the VWA wholesale price in the SA region for the entire 2008 calendar year by 27.3%. As set out in Table 1 above, there were either other episodes of market power in 2008. Each of those other episodes may have had a similar effect on the VWA wholesale spot price.

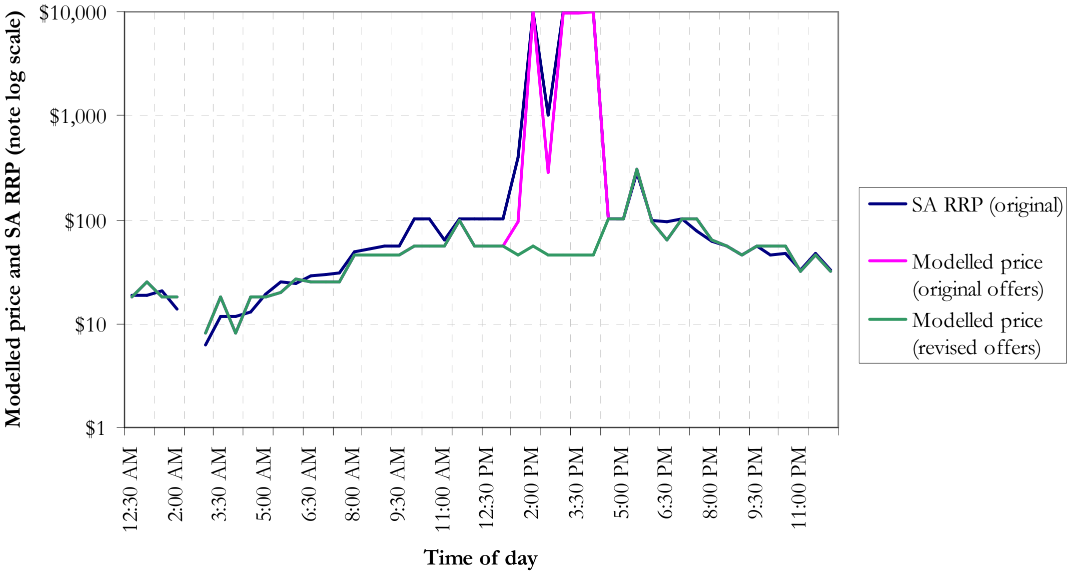
Table 2: Effect of two episodes of market power on the VWA prices for 2008

	VWA using out-turn prices	VWA using out-turn prices except for the periods when market power is exercised, when modelled prices are used.	Percentage increase in price due to market power
January 2008	$186.3	$99.5	87.2%
February 2008	$206.6	$48.8	323.5%
Q1 2008	$242.7	$165.8	46.4%
2008 calendar year	$92.8	$72.9	27.3%

This modelling exercise can, of course, be repeated for other days. Figure 24 shows the modelled price outcomes and actual price outcomes for 19 January 2009. As before AGL's offers for the high-priced were replaced with AGL's offer curve from earlier in the day (11 am or 11:30 am). As can be seen, the modelled prices fairly closely reflect actual prices. During the period in which market power is exercised, replacing the offer curve with the offer curve from earlier in the day results in significantly lower prices – the prices during this period are in the range $45-55/MWh compared with prices which are near the market price cap for much of this period.

As before, the one episode of market power on 19 January 2009 had a material impact on the VWA price for the SA region in 2009. Eliminating the market power by replacing the AGL offer curve with the offer curve from earlier in the day reduces the January 2009 VWA price from $373.5/MWh to $318.9/MWh. Put another way, this analysis suggests that the exercise of market power on just this one occasion increased the VWA for the month of January 2009 by 17.1%.

Figure 24: Modelling of the counterfactual price outcomes on 19 January 2009



Relationship between episodes of market power and high demand

There is a strong correlation between these episodes of market power and days of high demand in SA. 28 out of 35 of the episodes in table 1 occurred on days when the SA demand was greater than 2500 MW. All of the occasions where this withholding resulted in a spot price close to $10,000/MWh occurred on days when the SA demand was greater than 2500 MW.

There were 57 days in the period in question on which the SA demand peaked at 2500 MW or more. As just mentioned, of these days 28 were days on which TIPS priced more than 50 MW of capacity at more than $9000/MWh. On another 2 days, TIPS appeared to exercise market power by pricing around 300 MW at a high price, but less than $9000/MWh. In other words, out of 57 high-demand days, on 30 occasions TIPS appears to have been directly exercising market power with withholding capacity.

Of the remaining 27 days, 9 were days when the Administered Price Cap applied in SA, limiting the trading interval price to $300/MWh. On these days, TIPS has no incentive to exercise market power to raise the wholesale spot price above $300/MWh. Of the remaining 18 days, 9 were days where the sum of the spot prices in SA was high (above $120,000) and likely to breach the Cumulative Price Threshold if market power was exercised. This leaves 9 days in the period (out of 822) on which demand was larger than 2500 MW and there was no discernible exercise of market power by TIPS, and no price cap binding or threatening to bind.

This correlation between episodes of high demand in SA and the exercise of market power can be seen in Table 3. Out of the 822 days in the sample period, on almost all the days on which demand was high, market power was exercised (or the APC was binding or was threatening to bind). Similarly on almost all the days when demand was less than 2500 MW, no market power was exercised.

Table 3: Correlation between high demand days and days on which market power was exercised

	No capacity withdrawal, APC or high CPT	Capacity withdrawal, APC or high CPT
Peak demand < 2500	757 (92.1%)	8 (1.0%)
Peak demand > 2500	10 (1.2%)	47 (5.7%)

2.5 TIPS as a pivotal supplier

The previous sections have demonstrated that AGL has, on several occasions, exercised market power by pricing a large proportion of the capacity of TIPS at prices close to the market price cap, especially on days of high demand in South Australia. This bidding behaviour appears to have had a significant effect on the VWA wholesale spot price in the SA region.

What is the primary source of this market power? The analysis suggests that TIPS is a "pivotal" generator in the SA region at times of high demand when the VIC-SA interconnector is binding – that is, at times of high SA demand the total load in SA cannot be satisfied by other generation capacity or by interconnectors. At such times AGL can, in principle, increase the wholesale spot price in SA to the market price cap by re-pricing sufficient capacity close to the market price cap. To further explore this issue, this section looks at the total capacity of other generators and interconnectors to meet load in the SA region and how that has evolved over time.

In principle, we might simply sum the name-plate capacity of the other generators in the SA region and the nominal capacity of the interconnector and sum these values to find the maximum amount that could be supplied by other sources in the SA region. However this approach is inaccurate for several reasons. The capacity of the interconnector varies widely on a day-to-day basis and is seldom near its theoretical physical maximum. Intermittent generators (such as wind generators) typically produce much less than their nominal name-plate capacity. Even in the case of thermal generators, technical limitations may reduce their maximum output during the hot summer months (that is, the "summer rating" of a generator or the associated transmission equipment is typically less than the "winter rating"). Alternatively, some generators may be less reliable during the hotter summer months. The extent to which this approach overestimates the available capacity at peak times is highlighted in Figure 25 below.

A more accurate picture of the ability of other sources to supply load in SA can be achieved by looking at what these other sources *actually produced* at times of very high prices in SA. At such times all generators not exercising market power should be producing at or close to their physical maximum capacity at the time.

To construct Figure 25 below the output of all generators in SA (other than TIPS) was averaged over all the trading intervals in which the SA spot price was greater than $9000/MWh during the first quarter of 2008, 2009 and 2010. As can be seen in Figure 25, the largest generating stations in SA at these times (other than TIPS) are Northern Power (NORTHP) and Pelican Point (NPPPPS). Together these two stations account for approximately 1000 MW of output at these peak times. The other smaller generators, including the wind generators account for an addition 970 MW of output. The average flow on the interconnector at these times was 300 MW in 2008. The total capacity offered by the other generators and interconnectors at these peak times in Q1 2008 was therefore 2270 MW. This analysis suggests that when the demand in SA exceeded approximately 2300 MW in 2008, TIPS was a pivotal generator.

Figure 25 also provides an indication of how the capacity offered by other generation sources has evolved over time. By Q1 2009 the output of some generators had expanded – especially the wind farms. Hallett Wind Farm (HALLWF), Lake Bonney Wind Farm Stage 2 (LKBONNY_2), and especially Snowtown Wind Farm (SNOWTOWN) produced more in Q1 2009 than in Q1 2008 (the first stage of the Snowtown Wind Farm was completed in October 2008 and contributed, on average 40 MW of output in the peak price times in Q1 2009). However the output of the Playford Power Station (PLAYF) generator at these peak times was lower in Q1 2009 by 42 MW[62]. Even more importantly, the flow on the VIC-SA interconnector was 50 MW lower at these peak times in Q1 2009 compared to Q1 2008. Overall the total production from non-TIPS sources amounted to 2240 MW at peak times in Q1 2009 – suggesting that the threshold for the exercise of market power was, if anything, lower in 2009 than in 2008.

By Q1 2010 the output of the Hallett and Lake Bonney Wind Farms had increased even further, adding about 32 MW at peak times in Q1 2010. In addition, brand new wind farms at Hallett stage 2 and Clements Gap contributed an additional 40 MW at the peak times. However the largest change in production from 2009 to 2010 was due to an upgrade of the Quarantine power station, adding an addition 120 MW generating unit. This additional generating capacity was somewhat offset by a slight fall in the flows on the interconnector at these peak times, to 230 MW. Overall the total production from these non-TIPS sources at these peak times was around 2380 MW in Q1 2010.

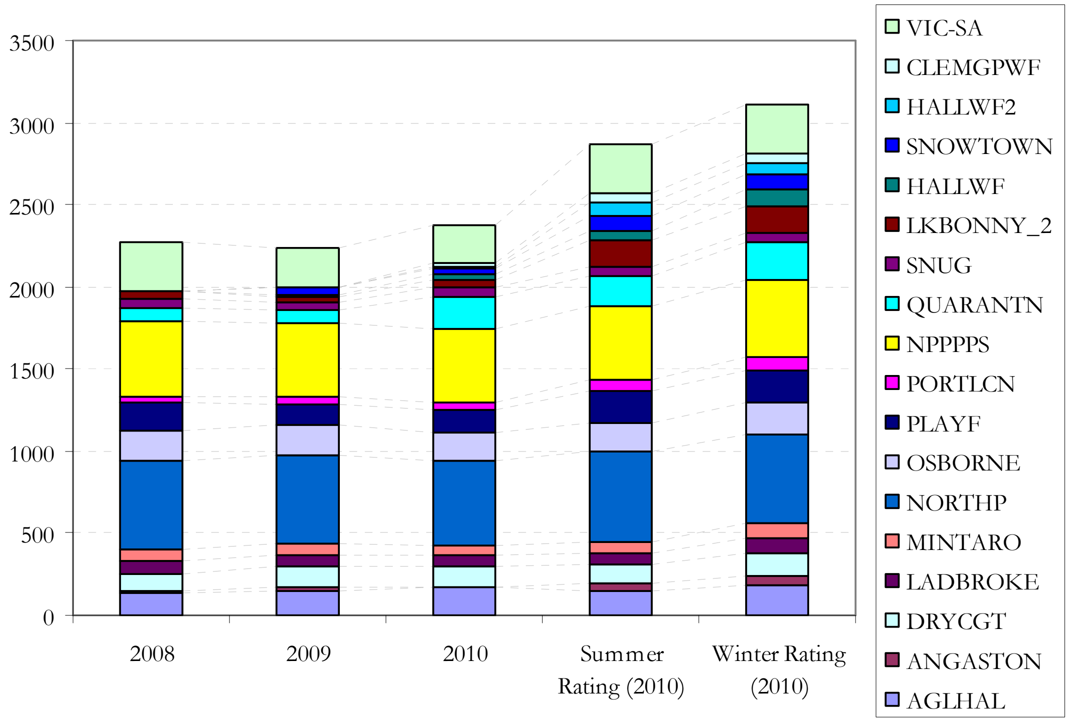
In summary, there has been new investment in the SA region over the period of this study, particular in wind farms (contributing about 100 MW at peak times) and the 120 MW upgrade of the Quarantine facility. The effect of this new investment has been partially offset by a decline in the flows over the interconnector at these peak times on the order of 70 MW.

Figure 25 also shows the nominal summer and winter capacity of the non-TIPS generation sources in SA (the interconnector has been assigned a nominal maximum capacity of 300 MW). As can be seen, none of the generators in the SA region produce at their maximum theoretical capacity at these peak times. Typically thermal generators produce 85-95 per cent of their theoretical peak capacity at these times. The wind farms produce 25-35 per cent of their peak capacity at these times. (Angaston produced only 12 per cent of its nominal capacity at these times but this is presumably due to the fact that AGL has control over the Angaston plant and was using it to exercise market power).

Overall, as can be seen, if we simply assumed that every generator in the SA region was able to produce at its theoretical maximum capacity we would draw the conclusion that TIPS is not pivotal until the demand in SA exceeds 2866 MW. Alternatively, if we (more realistically) assume that wind farms produce on average 30 per cent of their output at peak times we would conclude that TIPS is pivotal when the demand in SA exceeds 2554 MW.

[62] This is mentioned in the annual report of BBP: "both Playford and Northern were forced offline during high price events in January". BBP Full Year Result (Year ended 30 June 2009).

Figure 25: Output of generators in SA at peak price periods (Q1 2008, 2009, 2010)

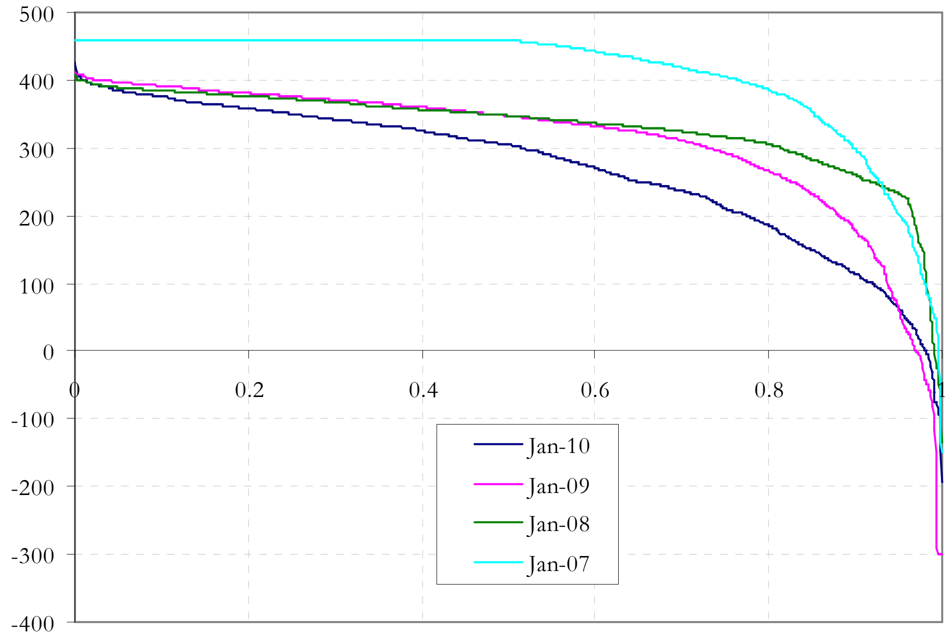


The analysis above shows that the flows on the interconnector (and therefore the ability of generators in other regions to offset an exercise of market power in South Australia) have tended to decline over time. This is further confirmed by examining the evolution of the VIC-SA export limit. Figure 26 below shows a histogram of the VIC-SA export limit over the month of January in 2007-2010. For each MW export limit on the vertical axis the graph shows the proportion of time that the export limit was at or below that level.

It is clear from this graph that the export limit on the VIC-SA interconnector has been eroding over time. In January 2007 the VIC-SA export limit exceeded 300 MW for 668 hours. In January 2008 this dropped to 606 hours. By January 2009 this has dropped to 543 hours and in January 2010 the export limit exceeded 300 MW for only 383 hours. There is an interesting question as to why the export limit is dropping in this way, but this question goes beyond the scope of this paper.[63]

[63] It seems likely to be related to increased wind farm output in South East South Australia.

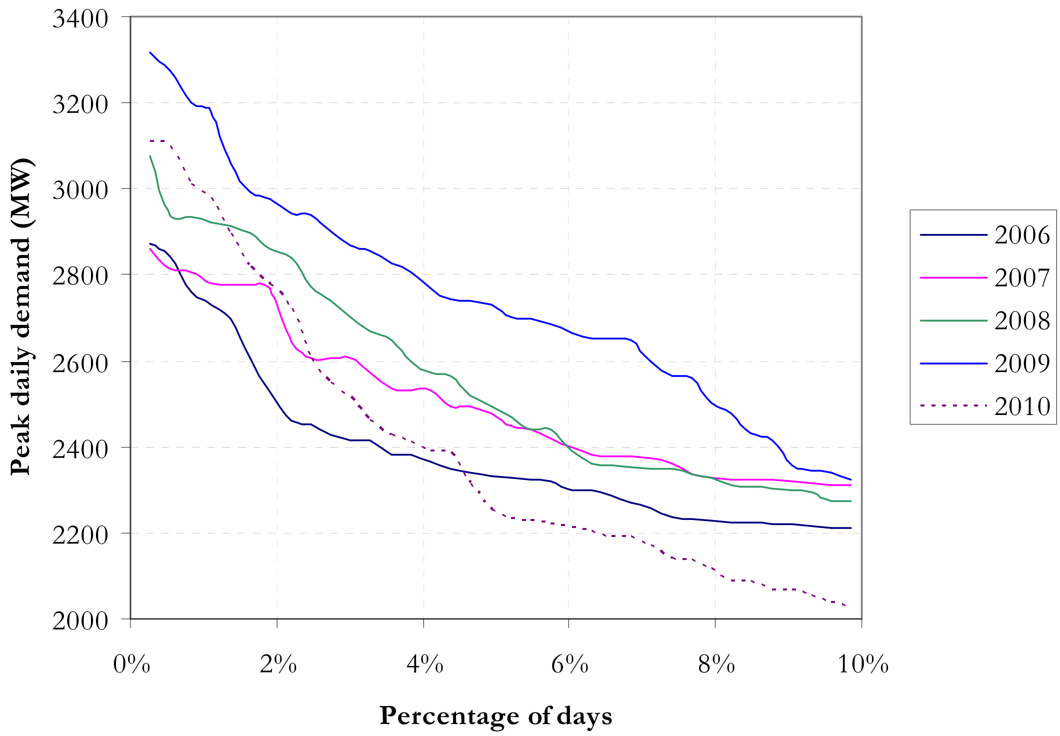
Figure 26: VIC-SA Export Limit Duration Curve January 2007-2010



The analysis above suggests that TIPS is, in practice, a pivotal generator in the SA region when the demand exceeds a threshold which lies in the range 2300-2500 MW, depending on the output of wind generators and on the precise export limit on the VIC-SA interconnector. In order to determine whether or not these opportunities for exercising market power are increasing over time we must look at how demand patterns have been changing over time.

Figure 27 shows the top end of the demand-duration curve for the SA region for the period 2006-2010. As can be seen, peak demand in SA has been shifting steadily upwards in the years 2006-2009. For example, in 2006 there were only 4 days when the peak demand exceeded 2700 MW. This increased to 7 days in 2007 and 11 days in 2008. In 2009 there were 19 days when peak demand exceeded 2700 MW. During the period 2006-2009 the number of opportunities for the exercise of market power seems to have increased each year. 2010 is, of course, not yet half way through. However it appears that 2010 will be a cooler year, with not as many days with high demand as 2009.

Figure 27: Peak Demand-Duration Curve for the SA Region 2006-2010



2.6 The impact of this market power on the hedge markets and the retail market in SA

As discussed in chapter 1, the exercise of market power results in various forms of economic harm. There are short-term effects on productive and allocative efficiency. In the longer term, the exercise of market power can provide inefficient signals for generation investment. In addition, the exercise of market power can have an impact on the liquidity of the wholesale hedge market and on the level of competition in the retail market. This section explores the extent to which we can observe an impact of market power on the hedge markets and the retail market.

Let's first examine the impact of market power on the liquidity of the hedge market. It is worth noting that there has been a lack of liquidity in the SA hedge market for some time. A report published in October 2006 by PriceWaterhouseCoopers made the following comments:

> "The overwhelming majority of respondents (13 of 17) viewed South Australia as having insufficient liquidity … One respondent remarked that the risks of dealing in South Australia strongly incentivised operators in this region towards vertical integration or to form a generator-retailer alliance. Another respondent commented that although they do trade the South Australian market, they see the region as very risky and would think carefully before entering a short position. Another two players noted that lack of price transparency in this region makes it difficult for new entrants to evaluate risks and could be seen as a barrier to entry.
>
> Limited interconnection, with low levels of capacity, exacerbated by relatively extreme weather, were cited as reasons for high degrees of price separation with the rest of the NEM. The presence of what respondents perceive to be relatively few dominant players, high levels of vertical integration, and the small electricity demand were also cited as reasons for the low level of liquidity relative to other states"[64]

[64] PriceWaterhouseCoopers, "Independent survey of contract market liquidity in the NEM", October 2006.

More recently, in June 2010, ACIL Tasman published a report on competition retail markets in South Australia. That report noted:

> "The volatility in the [SA] spot price increased in 2008 and 2009, compared to 2006 and 2007, through the impacts of the drought, extreme weather events and the uncertainty associated with the potential introduction of a carbon price. As a result, the average spot prices also increased. Some participants were strongly of the view that the generator asset swap between AGL and TRUenergy also contributed to these changes. However, some participants were of the view that the timing of the asset swap was coincidental.
>
> … Now that participants are seeking contract cover, they are of the view that the South Australian contract market is illiquid. While some were of the view that there were no contracts available in the South Australian wholesale electricity market, others were of the view that contracts were available but at a price that could not be sustained with the headroom in the retail tariff and for too short a period. The buyers were generally of the view that the lack of liquidity was due to a lack of sellers in the market due to the power held by AGL as the dominant retailer and as a dominant generator with Torrens Island".[65]

Market power can itself be a cause of illiquidity or unwillingness to trade, particularly in markets where the counter-party is unknown. Muermann and Shore (2005) write:

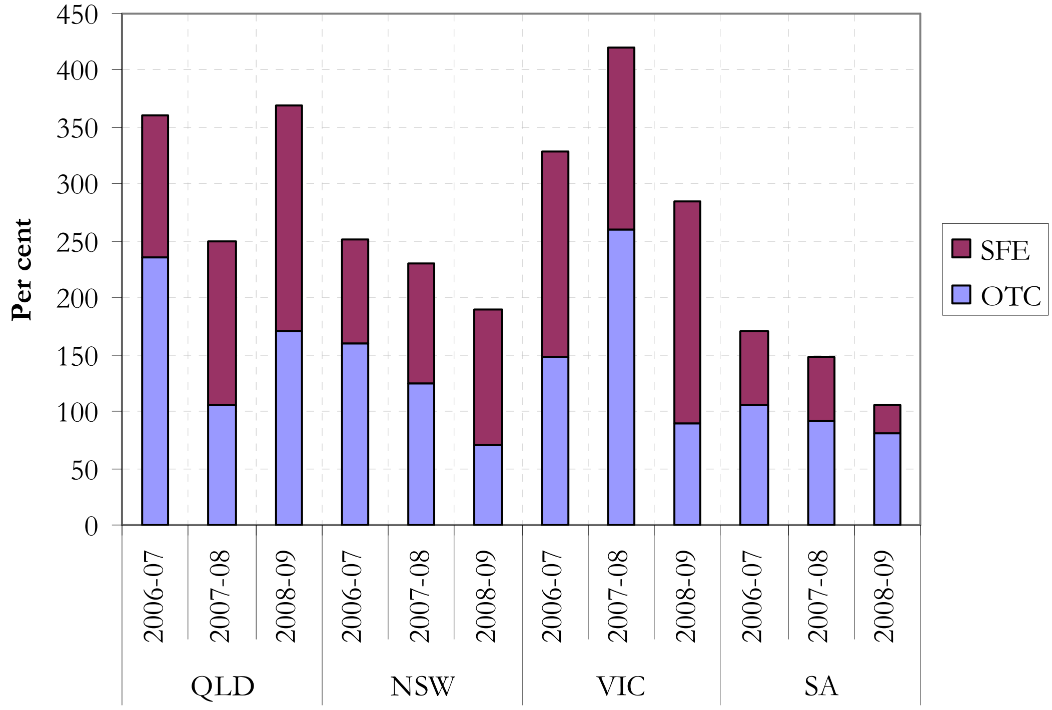
> "Even agents without market power may be discouraged from participating in a futures market when there is a spot market monopolist. When market makers cannot distinguish orders placed by those with and without market power, they set prices to reflect the possibility that their counterparty could have market power. This makes futures market participation expensive and therefore reduces futures market participation by those without market power. … Futures traders with spot market power can profit by exploiting their market power, thereby deterring participation by those without market power".[66]

Has there been any evidence of a decline in liquidity in the SA hedge market during the period studied in this paper? Figure 28 shows the trading volumes in the over-the-counter and Sydney Futures Exchange markets in the 06-07 to 08-09 fiscal years. As can be seen, the total volumes traded in SA (as a percentage of SA demand) have declined over this period. Interestingly, the volumes traded on the futures exchange (as compared to the OTC market) as a proportion of total SA trade has also declined. In 2006-07 (before the market power incidents in this report) around 38 per cent of the total volume of trading in SA hedges occurred on the SFE. By 08-09 this has declined to around 24 per cent.

[65] ACIL Tasman (2010), page 28.

[66] Muermann and Shore (2005).

Figure 28: Regional trading volumes as a percentage of regional NEM demand



Source: AER, State of the Energy Market 2009, Figure 3.10, page 101.

Is there any evidence that this exercise of market power and/or lack of hedge market liquidity are having an impact on the level of retail competition in the SA region?

ESCOSA produces annual reports on the performance of the electricity market in South Australia in November of each year. The most recent of these, published in November 2009 relates to the 2008-2009 fiscal year.

The report for 2007-08 summarises retail customer switching rate data published by AEMO. Figure 3.2 of that report shows the SA switching rate declining from an annualised rate of over 25 per cent in the first half of 2007 to around 17-18 per cent by the end of 2007. However, in the first few months of 2008, following the start of the episodes explored in this paper, the switching rate declines more rapidly to the range of 10-15 per cent. In comparison, the annual average switching rates were 23% in Queensland, 22% in VIC and had previously been 24% in SA. The average annualised switch rate in NSW in 07/08 was 10%. The most recent data shows that the reduced switching rate has continued until June 09.

In the most recent (2008-09) report ESCOSA expressed concerns about the level of retail market competition. ESCOSA noted:

> "Latest indicators suggest that … the observed degree of competitive forces within the market over the past two years has been less intense than in the past, as evidenced by the reduced rates of switching away from the regulated 'standing' contract, continued reduced levels of marketing by retailers and less price discounting overall".[67]

In its discussion of the number of retailers ESCOSA notes:

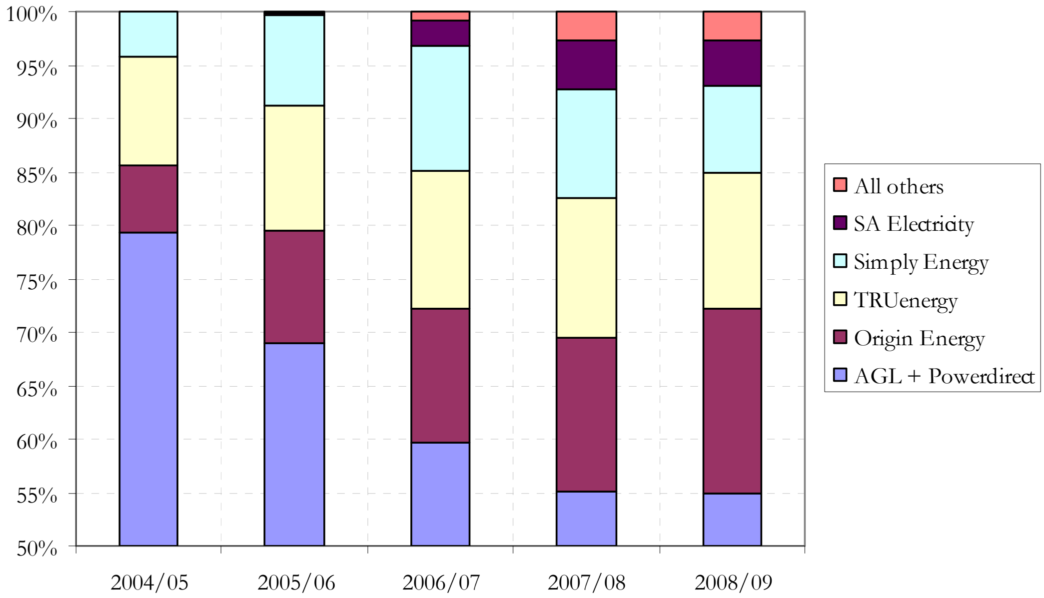
> "Some retailers, while continuing to sell energy to their existing customer base, ceased actively marketing to new customers during 2007/08, and this trend has continued during 2008/09. In addition, in 2008/09, some retailers have commenced a process of

[67] ESCOSA Annual Performance Report, SA ESI, November 2009, page 2.

not renewing existing customer contracts when they reach their term, thereby actively reducing their customer bases in this State."[68]

Figure 29 shows how the market share of the largest retailers has evolved over time in SA. Following several years of rapid loss of market share, AGL reversed this decline in the 08/09 financial year. In that year AGL (including its subsidiary PowerDirect) won back 13,000 customers in SA. This increase came primarily at the expense of Simply Energy and some of the other smaller retailers. Origin continued to gain market share in this time. ESCOSA notes that "the slowing of growth in new entrant market share is consistent with the decision of some retailers to reduce active marketing to small customers".

Figure 29: Evolution of retail market share in SA



ESCOSA also notes that "the number of market offers that were priced at a level below the electricity standing contract price declined during the year". As of October 2008 there were 16 market offers which were at a discount to the residential standing contract (two of these were by AGL or its subsidiary PowerDirect). In contrast, as of September 2009 there were only 8 market offers which were at a discount to the residential standing contract and 4 of these were by AGL or its subsidiary PowerDirect. ESCOSA notes that "the standing contract price now sits towards the bottom end of the range of all contract prices available to customers. This is a notable change from earlier years when the standing contract was effectively a 'ceiling' price and almost all other retail offers were set at either the same level or a discount to that price".

Overall, this data suggests a reduction in the intensity of competition in the SA retail market, particularly from 2008 on. ESCOSA puts the reduction in the level of competition down to the following factors:

- "the impact of the global financial crisis on the general availability of funds for business investment and expansion;
- Reduced availability of longer term, price certain generator contracts; and
- Wholesale market uncertainties arising from the proposed carbon pollution reduction scheme".

[68] ESCOSA, page 24.

ACIL Tasman, in their recent report, note that several participants in the market argue that the exercise of market power by Torrens Island is, at least in part to blame for a reduction in retail competition:

> "A number of participants pointed to the bidding behaviour of the Torrens Island Power Station, especially on high demand days, as the underlying cause of the increased volatility in the South Australian spot price. In summary, these participants see AGL, as the owner of Torrens Island, as being 'in the box seat' with the ability to lift spot price to the market price cap when demand is high, thus earning a substantial profit on a few key days.
>
> Participants who hold the view that the volatility is caused by AGL's bidding behaviour also tend to see this as an inevitable result of AGL's large, vertically-integrated nature. These participants argue that AGL's bidding behaviour at Torrens Island is, at least partly, an attempt to suppress competition in the retail market. It is very important to note, though, that this was not a unanimous view".[69]

It is impossible to be certain that this reduction in retail market competition is due to the exercise of market power by AGL. Merely observing that one event followed another event in time is not necessarily evidence of causation (this is the *post hoc ergo propter hoc* fallacy). Nevertheless, conventional theoretical grounds would have predicted these outcomes – that the exercise of market power would reduce liquidity in the hedge markets and that it would "squeeze" retailers between a fixed standing contract tariff and high and increasingly volatile input prices. It is at least possible that some of the reduction in competition in the SA retail market is due to the exercise of market power.

2.7 The incentives on a retailer to exercise market power

We have seen that since 1 January 2008 AGL has on many occasions exercised significant market power in the South Australian region of the NEM. This section explores the incentive on AGL to exercise market power.

As noted in chapter 1, the incentive to exercise market power depends critically on the net hedge position of the firm owning the generator. The net hedge position depends on the total volume of contracts bought or sold by the firm including traditional hedge contracts (including swaps and caps) and the total volume and nature of end-user or retail contracts.

We also observed in chapter 1 that most generators in the NEM prefer to be hedged for a majority of their output most of the time. However, perhaps TIPS is not a standard generator in this regard. Is there some reason why TIPS might choose to go unhedged?

Market uncertainty as a deterrent to hedging

One possible explanation why a generator might choose to go unhedged is uncertainty about the future evolution of the market.

It is possible that TIPS might withdraw from the market once a CPRS mechanism is put in place, which could explain why it is reluctant to hedge – since it would be unwise to sell hedge contracts when it cannot be sure it will have the generation assets to support that commitment in the future. In other words, it may simply choose to remain unhedged as long as there is uncertainty about the precise timing of the CPRS. As long as TIPS chooses to remain unhedged in this way it would retain a significant incentive to exercise market power.

This position is, at least in part, supported by comments by market participants reported in a study by ACIL Tasman:

> "To maximise returns in the short term, generators may … adopt a riskier strategy by contracting less and seeking to maximise the wholesale spot price. … [O]ne participant who is fully aware of this issue, indicated that this may be a factor in the bidding strategy

[69] ACIL Tasman (2010), page 32.

for Torrens Island. In this regard, ACIL Tasman notes that much of the electricity market modelling of an emissions trading scheme indicates that Torrens Island is likely to retire shortly after the introduction of an emissions trading scheme".[70]

In summary, perhaps TIPS is behaving in a manner which suggests it is largely unhedged because it is, in fact, unhedged – due to uncertainty over the timing of the CPRS and its own retirement from the market.

The impact of wholesale prices on downstream retail prices as a deterrent to hedging

A second possible explanation why a generator might choose to go unhedged relates to the impact of wholesale prices on future retail prices.

We noted earlier that, since AGL is a net retailer in SA (that is, it has a larger retailer load than generation capacity), it might be presumed that AGL would operate TIPS in such a way as to *reduce* rather than increase the wholesale spot price in SA, since any increase in value achieved on the wholesale side would be offset by a reduction in value on the retail side. AGL, it might be argued, should operate TIPS in a more competitive manner than a standalone generator. However, this argument assumes that there is no impact of the wholesale spot prices on both short-term hedge prices and on the downstream retail prices.

An exercise of market power typically involves four effects – a reduction in the output of the generator exercising market power, an increase in the wholesale spot price, a possible increase in future wholesale hedge prices, and a possible increase in the retail contract prices.

For our purposes, the key question is the extent to which an increase in average wholesale spot prices results in an increase in the retail contract prices. In practice this link may be indirect – that is, an increase in the average wholesale spot prices might result in an increase in the wholesale hedge prices which, in turn, results in an increase in the retail contract prices. In addition, the retail contract prices are themselves partly affected by competition conditions in the retail market and by the policy of ESCOSA in setting the standing contract or default retail tariff.

Overall it seems likely that a material exercise of market power in the wholesale market will have some impact on the retail contract prices. Conversely it is implausible that a material exercise of market power in the wholesale market would not have some impact on the downstream retail price, at least in the medium to long term.

If there is no pass-through of wholesale spot prices to retail prices then a net retailer has no incentive to exercise market power. A retailer acquiring generation assets might be long in generation in the short term (and therefore might have an incentive to exercise market power) but would be expected to sell some of its hedge contracts and, once it returned to a balanced position, the net hedge position of the retailer would be expected to match the output of the generator and the retailer would not have any incentive to exercise market power.

However, the situation is different if the increase in wholesale prices results in an increase in retail prices. In this case, although an exercise of market power hurts the integrated firm in the short-term, it increases the retail price, which benefits the firm in the longer term. This longer-term benefit partially offsets the short-term cost. In effect, the firm behaves as though it is not as highly hedged. In fact, if there is quite a strong pass-through from wholesale spot prices today to retail prices in the future, the integrated firm will behave as though it is almost entirely unhedged – that is, it will exploit almost every opportunity to exercise market power.

In assessing the competitive effect of a generator-retailer merger, whether or not the combined entity will have an *increased* incentive to use any market power relative to the market power that the standalone generating entity currently enjoys depends on whether the retail arm of the merged entity has, on balance, an incentive to manipulate spot prices to either increase the retail price or decrease hedge prices. This depends in turn on the sensitivity of the retail price and

[70] ACIL Tasman (2010), page 37.

hedge prices to the current spot price and the level of retail hedging relative to the size of the retail load.

Consider the case where the retail price is set by a regulator every few years. Suppose that the regulator, in setting the retail price, takes into account either recent spot market outcomes or hedge prices. In the months prior to a price-determination decision a combined generator-retailer knows that any exercise of market power will flow through into its end-user prices for the next few years. As a result, its retail load provides virtually no constraint on its incentive to exercise market power. It will exercise market power to push up the hedge price and therefore the retail price (regardless whether it is a "net generator" or a "net retailer")." [71]

AGL has argued to the SA retail regulator that retail prices should be set on the basis of wholesale hedge contracts. AGL submitted its proposal for the level of the regulated retail tariffs for the next three years to ESCOSA on 25 May 2010. In its proposal AGL recommended that (in the event the regulation of default retail tariffs was not removed), ESCOSA adopt the so-called "Relative Price Movement Approach" under which the "the weighted average rate of change in all market contracts will determine the rate of change in standing contract prices".[72]

In summary, the theory suggests that if wholesale market power affects downstream retail prices a retailer acquiring generation assets has a strong incentive to exploit any market power enjoyed by those generation assets even if the retailer maintains an overall balanced hedge position. This is a possible partial explanation for the observed bidding behaviour of AGL in the past three summers.

"Tipping" behaviour in the hedge market

A third possible explanation why a generator might choose to go unhedged is suggested in Biggar and Hesamzadeh (2010). That paper focuses on modelling the hedging decision of a generator with market power. A key result of that paper is that when the traders in the hedge market cannot directly observe the hedge position of the generator with market power (which seems likely), the profit-maximising choice of hedging for that generator is at the extremes – that is, to either be fully hedged or to be completed unhedged.

This conclusion is at least broadly consistent with the observed market outcomes. In the early 2000s, the owner of TIPS was able to hedge to a high level for a period of about five years. However, as those contracts expired around 2007, it chose not to renew them, leading to a further period of several years of being essentially unhedged and substantial market power.[73] In more recent months, TIPS is again behaving as though it is fully hedged.

A key conclusion of the Biggar-Hesamzadeh (2010) paper is that wholesale spot market power can be expected to have a substantial impact on liquidity in the hedge market, again, broadly consistent with what has been observed in SA.

Whatever the precise reason for AGL's actions, ACIL Tasman reports that at least some market participants believe that market power is hindering retail competition in SA and that steps should be taken to reduce the wholesale market concentration in SA:

> "…[A] number of participants consider it prohibitively difficult to compete in the South Australian electricity market because wholesale spot prices are too volatile and hedging contracts are not available at reasonable prices resulting in average wholesale electricity prices that are too high relative to the regulated retail price cap.
>
> A number of participants attribute these difficulties directly to the fact that the ownership of the South Australian electricity generation capacity has become

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[71] Biggar (2005b)

[72] AGL (2010).

[73] Under this perspective, the change of ownership of TIPS during 2007 is essentially irrelevant to the exercise of market power.

increasingly concentrated in recent years. In particular, these participants identify AGL's acquisition of Torrens Island as a cause of volatility, high prices, and financial market illiquidity.

The participants who held this view generally take the view that the Australian Competition and Consumer Commission made a mistake when it allowed AGL to acquire Torrens Island. They see this as an error that should ideally be reversed, although many of them hold the view that this is not possible under existing law."[74]

2.8 Conclusion

This chapter has examined the exercise of market power in the South Australia region of the NEM in the period 1 January 2008 – 31 March 2010. During this period market power was primarily exercised by AGL in its control over the TIPS plant (and to a lesser extent, indirectly, its control over the Angaston plant). Evidence was presented that AGL exercised market power by re-pricing large amounts of capacity to a price near the market price cap, particularly on days when the peak demand in SA exceeded 2500 MW. This exercise of market power resulted in the wholesale spot price reaching the market price cap for many hours during this period. On several occasions the Cumulative Price Threshold was exceeded and an Administered Price Cap regime was put in place.

The analysis suggests that TIPS is a pivotal generator in the SA region when SA demand exceeds approximately 2400-2500 MW. At these times AGL can, in principle, raise the price to the market price cap by withdrawing sufficient capacity from the market through re-pricing into high price bands. The threshold at which TIPS is pivotal has risen slightly due to some generation investment in the SA region (particularly at the Quarantine station, but also due to wind farm investment), but has dropped slightly due to a deterioration in the export capacity of the VIC-SA interconnector. During the period 2006-2009 peak demand in SA grew steadily from year to year, increasing the number of days on which demand exceeded the threshold and TIPS had the opportunity to exercise market power. So far in 2010, there have been fewer opportunities for the exercise of market power.

This chapter has suggested three possible explanations as to why AGL may be behaving in this way. One possible explanation relates to the observation that TIPS may be only marginally profitable under current market conditions. If it expects to leave the market in the near future (due to, say, the introduction of a CPRS) it would have relatively little incentive to sell hedge contracts and would retain a strong incentive to exercise market power. Another possible explanation relates to the influence of the wholesale spot price on the downstream retail price. Where there is a high level of pass-through from the wholesale spot price to the downstream retail price a retailer purchasing generation assets may have significant incentives to exercise market power. A third possible explanation relies on the observation that a generator with market power in the wholesale spot market has an incentive to choose an "all-or-nothing" approach to hedging. This is consistent with the observed outcomes in the SA market, and the apparent lack of liquidity in that market.

In my view, the extent of the exercise of market power by AGL in SA is significant, with a material impact on prices and dispatch in the SA region. This market power has persisted for three consecutive summers. Although there has been some new investment in generation capacity in the SA region, peak demand has also been increasing, and AGL has announced a major expansion of the Torrens Island plant. In more recent months it appears that TIPS has not been exercising market power. However, it appears possible that opportunities for market power will continue in the future.

Let's turn now to look briefly at other the scope for market power in other regions of the NEM. Although time does not allow for an exhaustive study of all regions on the NEM, to further

[74] ACIL Tasman (2010), page 46. ACIL Tasman emphasise that these were not the views of all market participants. ACIL Tasman also reports that participants argued for the removal of retail price regulation or, at least, an increase in the regulated retail price cap.

understand how market power might be being exercised in the NEM let's turn now to an exploration of the market power exercised in the QLD region of the NEM.

CHAPTER 3: THE EXERCISE OF MARKET POWER IN THE QUEENSLAND REGION OF THE NEM

3.1 Introduction

The exercise of market power in the Queensland region of the NEM follows a very different pattern to the exercise of market power in the South Australian region of the NEM. The following list summarises the key differences between the exercise of market power in South Australia (SA) and the exercise of market power in Queensland (QLD):

- Whereas in SA, market power is predominantly unilateral behaviour by one company (AGL), in QLD, the exercise of market power seems to involve simultaneous actions by a number of different generating companies;

- Whereas in SA, the exercise of market power tends to be relatively infrequent (limited to only the highest demand days), the exercise of market power in QLD is significantly more frequent, (occurring on roughly two in every five days during summer);

- Whereas in SA, the exercise of market power tends to involve the withdrawal of a very large share of the capacity of one generating plant, in QLD, the exercise of market power seems to involve the concerted withdrawal of a relatively small proportion of capacity across a number of generating plants.

- Whereas in SA, the exercise of market power tends to results in very high spot prices (close to the market price cap), in QLD, when market power is being exercised the price in QLD remains relatively moderate (typically in the range $30-$300/MWh).

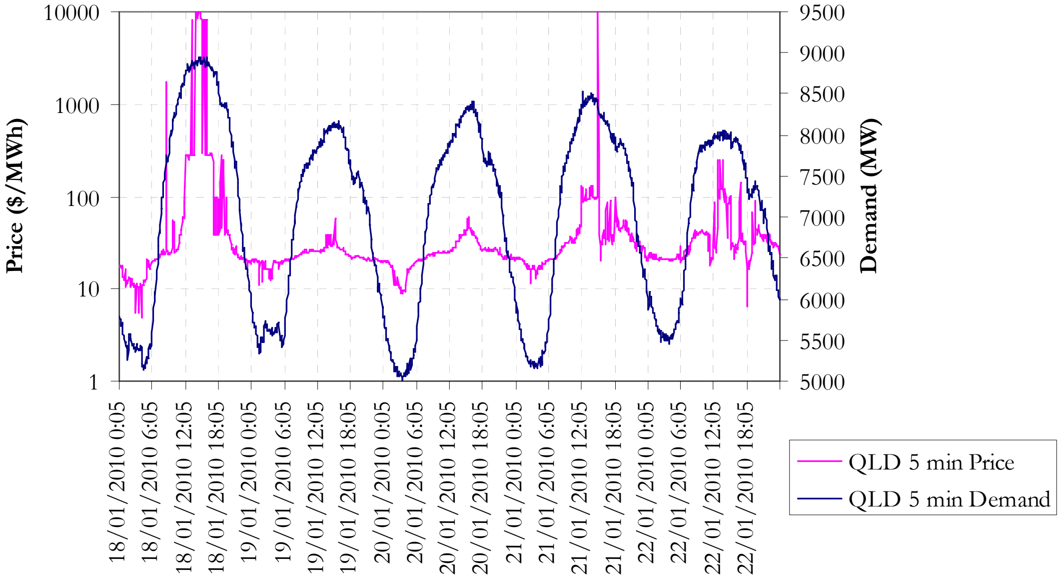
At the same time, there are some similarities. The exercise of market power in both QLD and SA is heavily influenced by the presence of constraints on the interconnectors between these regions and the rest of the NEM. In the case of the SA region, market power is exercised primarily when transmission limits constrain flows from VIC into SA. In contrast, in the QLD region, market power appears to be exercised both when flows are at their limit in the northward direction over the NSW-QLD interconnectors (in which case the exercise of market power exacerbates the transmission constraint) and when flows are at their limit in the southerly direction on the NSW-QLD interconnectors (in which case the exercise of market power alleviates the transmission constraint).

The following sections illustrate the patterns of the exercise of market power in QLD through an examination, first, of specific episodes of market power in early 2010, and, subsequently, with an examination of what we can say about all the episodes of market power that have occurred in the current financial year.

3.2 Examples of market power in QLD

The following graphs illustrate the patterns of the exercise of market power in Queensland on five consecutive days in January 2010 (Monday 18 January 2010 – Friday 22 January 2010). Figure 30 below shows the QLD demand and the 5 minute price for the QLD region. This was a week of high demand in the QLD region. The peak demand for 2010 so far was reached on Monday 18 January 2010 and the peak demand on all the days of the week exceeded 8000 MW (which is exceeded on roughly ten per cent of days in the year).

Figure 30: 5 minute price and demand outcomes in QLD 18-22 January 2010



On this week the NSW-QLD interconnector reached its limit in the northerly direction for several hours in the afternoon on each day. A number of the generators in QLD took this opportunity to exercise market power. Figure 31 shows the pattern of withholding by Millmerran. Millmerran priced around 220 MW into high priced bands during much of the afternoon for each day this week except for Wednesday.

Figure 31: Withholding by Millmerran 18-22 January 2010

Similar behaviour can be seen at the Callide C plant (Figure 32 below). Callide C withheld around 230 MW on the Monday (when demand was the highest). The withholding on Tuesday and Wednesday was strictly limited in both amount and duration (lasting just one hour and reducing station output by only around 50 MW – possibly due to plant problems). On Thursday Callide C withheld 131 MW and on Friday just under 70 MW. Millmerran and Callide C are both 50 per cent owned by InterGen. The other 50 per cent of Callide C is owned by CS Energy (which is owned by the Queensland government).

Figure 32: Withholding by Callide C 18-22 January 2010

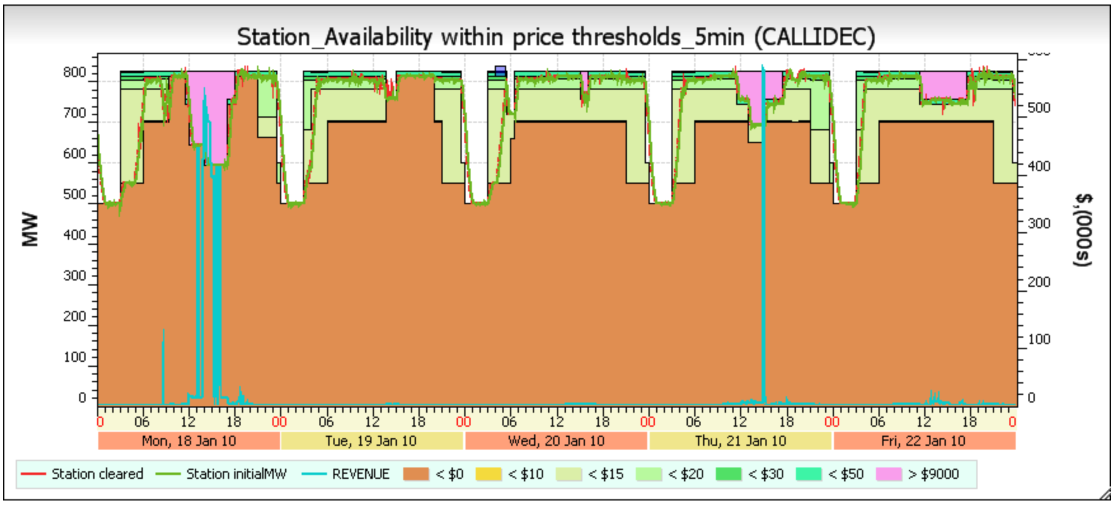
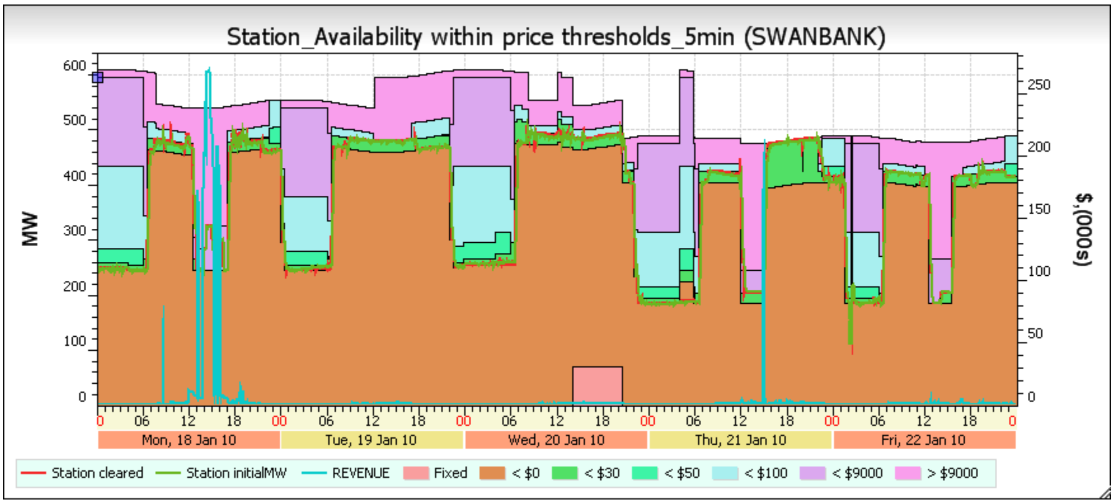


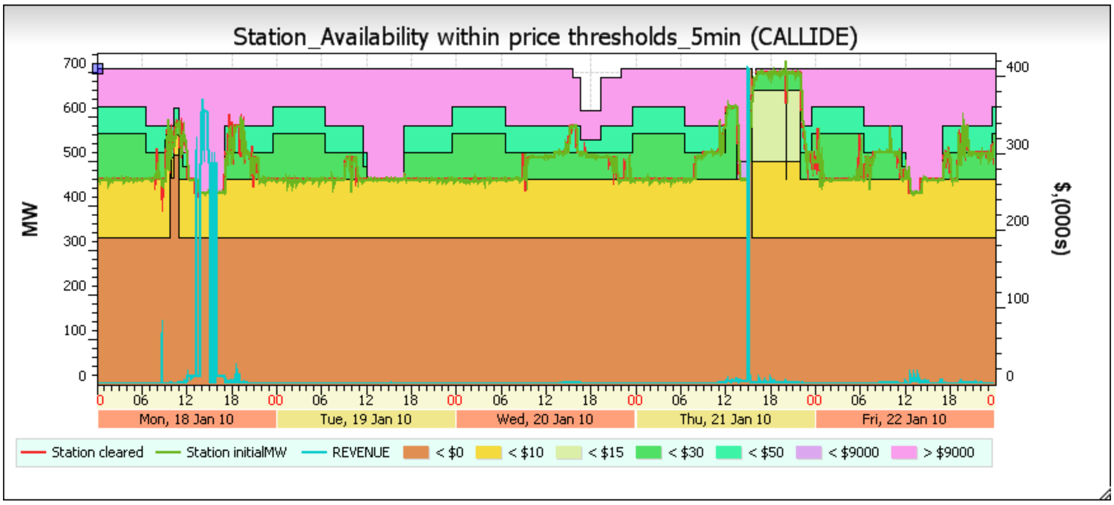
Figure 33 and Figure 34 show the bidding behaviour by the two other plants wholly-owned by CS Energy – Swanbank and Callide. As can be seen, Swanbank was withholding around 300 MW on the Monday afternoon (with around 250 MW priced above $9000/MWh). On Tuesday and Wednesday afternoon the withholding at Swanbank is indiscernible from the day-to-day underlying variation in bidding strategies. On Thursday and Friday, however, Swanbank was withholding more than 250 MW by offering this capacity in high price bands.

Figure 33: Swanbank market offers 18-22 January 2010



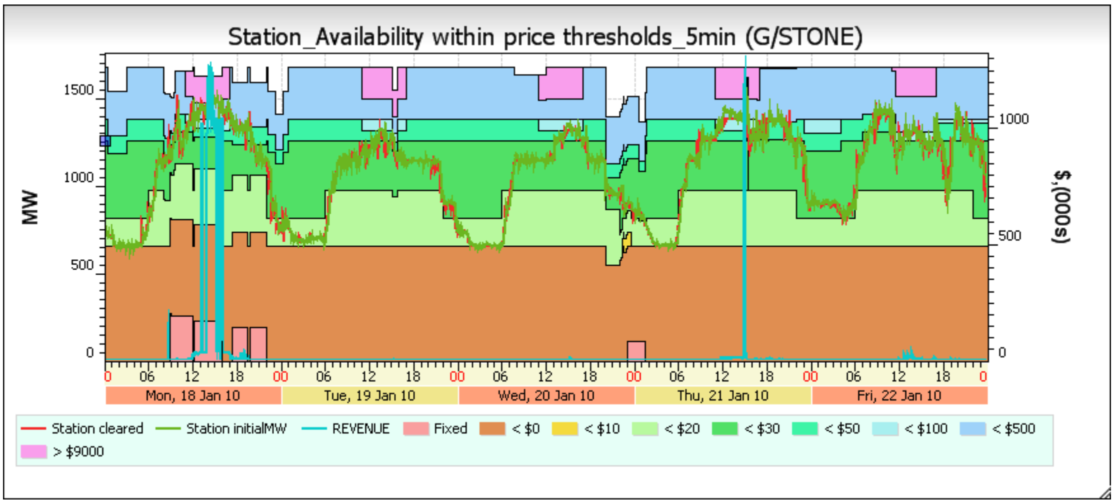
The bidding at Callide follows a similar pattern. Callide routinely offers around 130 MW of its capacity in high price bands. However, on the afternoon of Monday, Tuesday and Friday, the amount offered in high price bands increased to a total of 280 MW, reducing Callide's output by around 150 MW at this time.

Figure 34: Callide market offers 18-22 January 2010



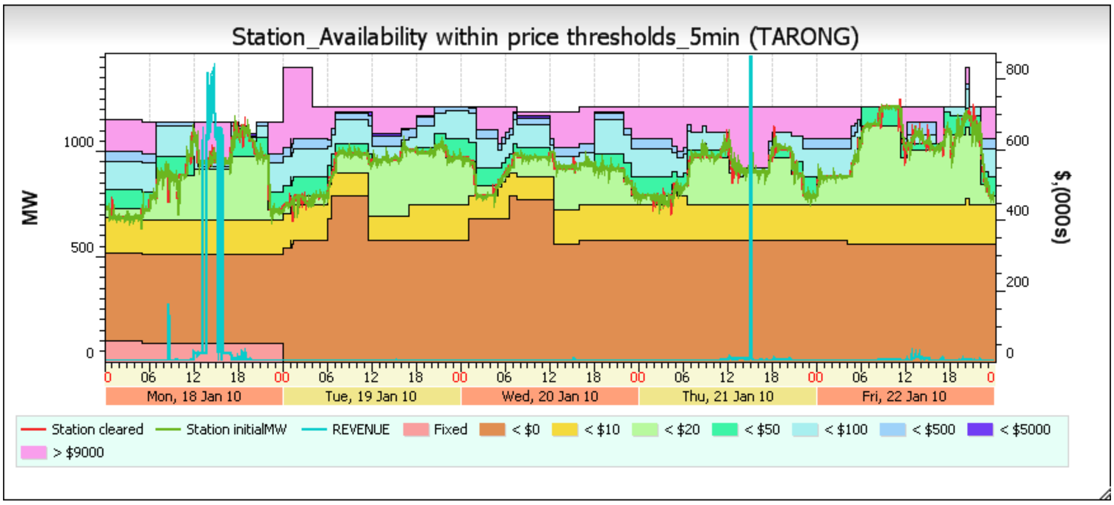
The other large generators in the QLD region are Stanwell Corporation and Tarong Energy. Figure 35 shows the bidding behaviour of Gladstone (operated by Stanwell Corporation) during this same week. As can be seen, Gladstone also re-priced around 180 MW of capacity into high-priced bands on each day Monday-Friday. Interestingly, this re-pricing had virtually no impact on the dispatch of Gladstone (with the possible exception of the Monday, when Gladstone's output was probably somewhat limited by bidding in this way).

Figure 35: Gladstone market offers 18-22 January 2010



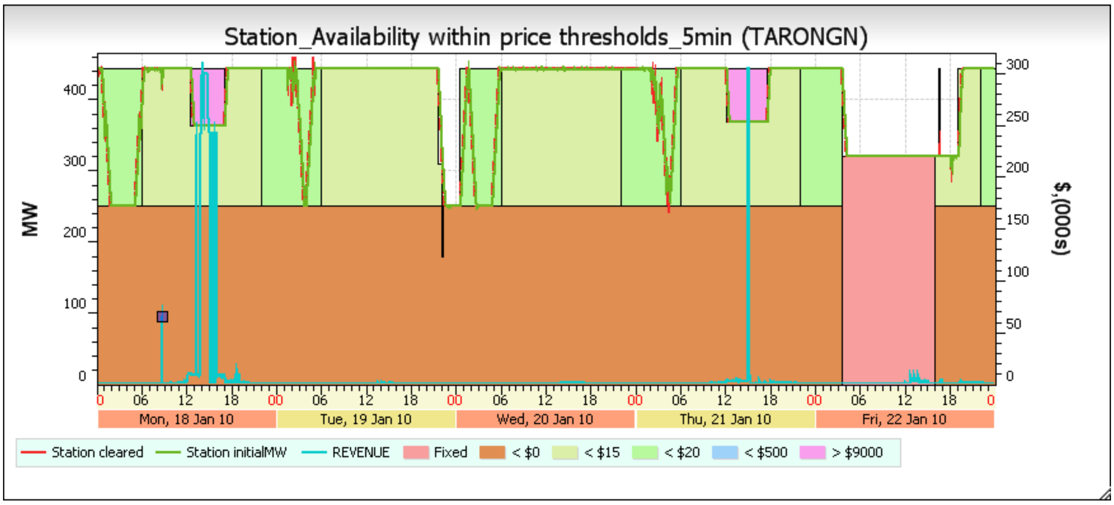
The largest generator owned by Tarong Energy is the Tarong Power Station. As can be seen in Figure 36, Tarong also re-priced some of its capacity during this week, offering around 200 MW in high priced bands on Monday, 125 MW on Tuesday, 170 MW on Wednesday, 290 MW on Thursday, and up to 170 MW on Friday.

Figure 36: Tarong market offers 18-22 January 2010



Tarong Energy also owns a 50 per cent share in the Tarong North Power Station which also participated in this same strategy, withholding 75-80 MW on Monday and Thursday.

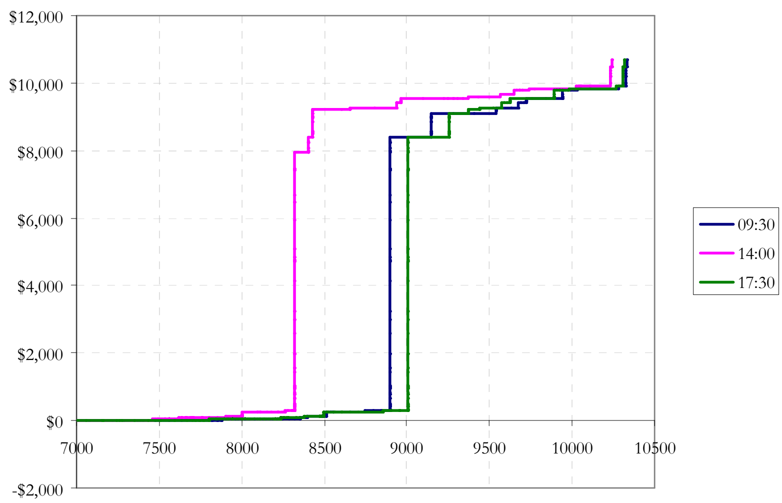
Figure 37: Tarong North market offers 18-22 January 2010



Altogether, if we add up all of the capacity offered above $9000/MWh on these days we find that the total capacity offered in high price bands reached 1400 MW on Monday, around 1300 MW on Thursday and 1000 MW on Friday. This amounts to around 13-16 per cent of the QLD demand at the time. This is smaller than, but still comparable to, the amount withheld by TIPS in SA, which is in the range of 10-30 per cent of the SA demand on peak days.

We can obtain an idea of the effect of this withholding by closer examination of the supply curves at these times. Figure 38 shows the supply curve on Monday 18 January 2010, at 9:30 am, 2 pm, and 5:30 pm. As can be seen, the capacity priced below $500/MWh dropped by 600-700 MW in the early afternoon relative to the capacity offered at 9:30 am and 5:30 pm. At 9:30 am the total net demand from QLD generators (QLD demand less interconnector flows) was around 7750 MW, resulting in a price around $25/MWh. By 2 pm, the net QLD demand had increased to around 8750 MW, resulting in a price close to the market price cap. By 5:30 pm, the QLD net demand had dropped to around 8600 MW which, once the withheld capacity had been restored, resulted in a price around $40/MWh.

Figure 38: QLD region supply curves 18 January 2010



In the episode described above, the interconnector flows were at their limit in the northerly direction. However, market power is also occasionally exercised in QLD at times when interconnector flows are at their limit in the southerly direction. In this case the primary purpose of the market power is to alleviate the transmission constraint and allow access to higher prices in the neighbouring region.

The graphs below show the pattern of the exercise of market power on 20 November 2009. On this day, prices were high in NSW for much of the morning and early afternoon. Demand in NSW on this day was high – peaking at over 13000 MW, a level which it has only reached on a few occasions over the past year.

Figure 39: 5 minute price and demand outcomes in QLD 20 November 2009

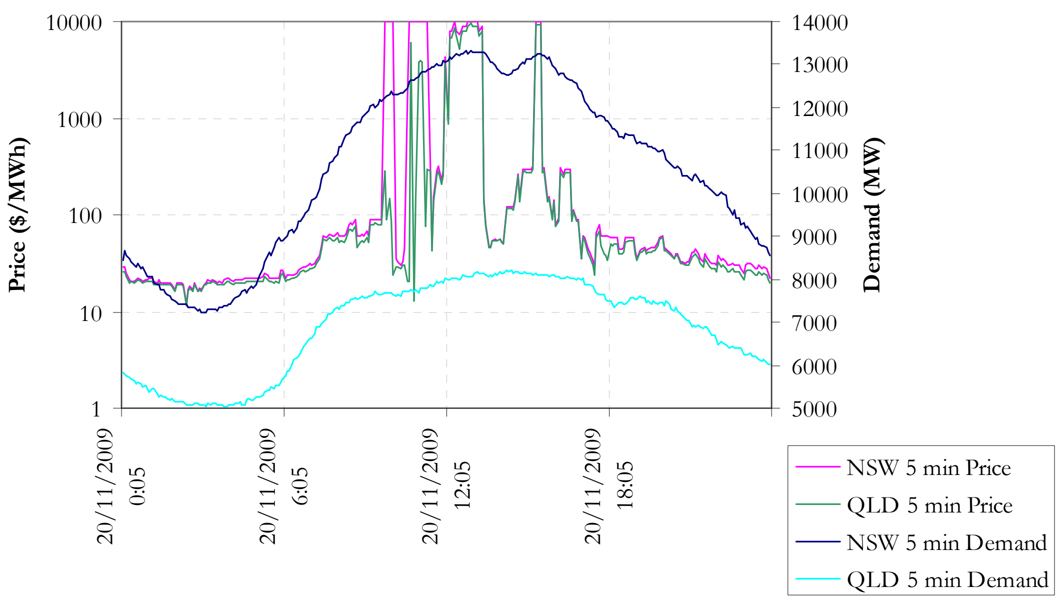


Figure 40 shows the bidding behaviour of Millmerran and Callide C (which are independently operated power stations, but both are 50 per cent owned by Intergen). As can be seen, Millmerran was offering around 250 MW in high price bands, while Callide C was withholding around 70 MW.

Figure 40: Millmerran and Callide C market offers 20 November 2009

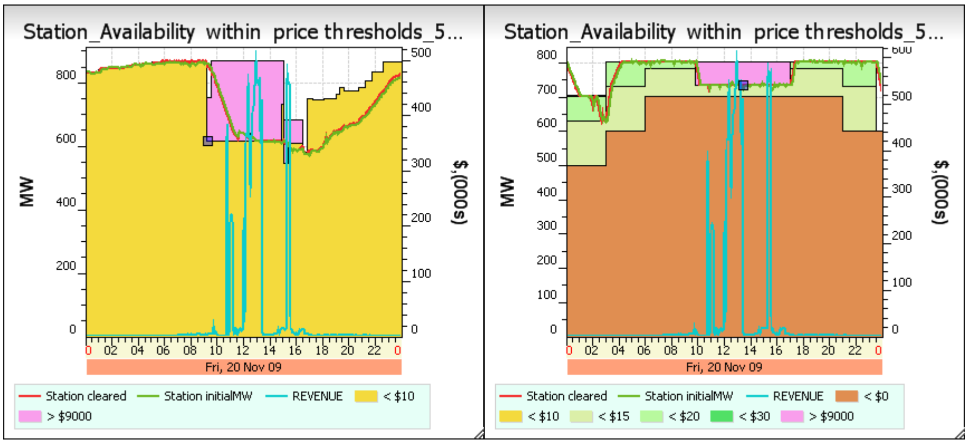
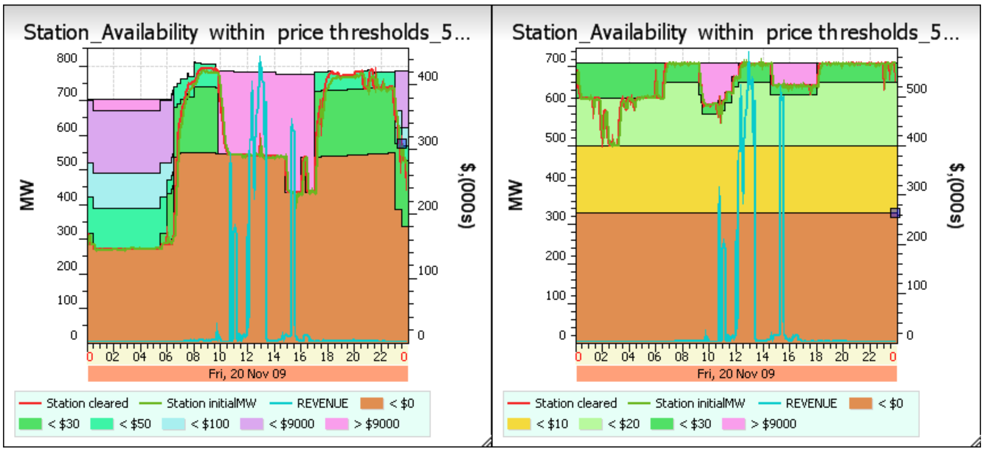


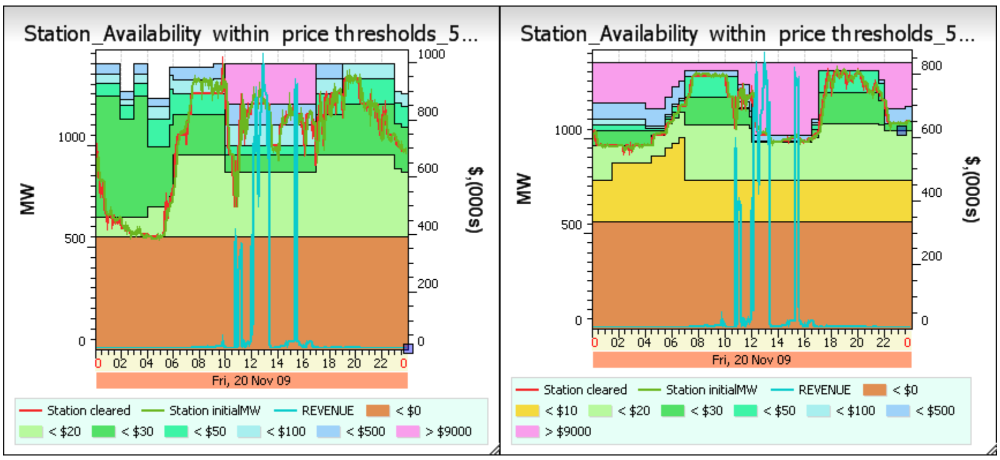
Figure 41 shows the bidding behaviour of Swanbank and Callide (both owned by CS Energy). Swanbank was withholding up to 340 MW on this day, while Callide was withholding up to 100 MW.

Figure 41: Swanbank and Callide market offers 20 November 2009



As before Stanwell Corporation was also participating in this withholding, repricing around 200 MW in to high price bands, and another 200 MW into intermediate price bands at its Gladstone power station (Figure 42). The second graph below shows the behaviour of Tarong Energy at the Tarong power station (the Tarong North power station – 50 per cent owned by Tarong Energy - was not operating on this day and didn't restart until 1 December 2009).

Figure 42: Gladstone and Tarong market offers 20 November 2009



The examples above are illustrative of the patterns of the exercise of market power in QLD. Specifically:

- Market power in QLD appears to involve the simultaneous withholding of relatively small amounts of capacity by a relatively large number of independent generating stations. This raises the question whether there is some form of implicit or explicit arrangement between these firms.

- The exercise of market power in QLD occurs at times when the NSW-QLD interconnectors are operating at their physical limits, in either the northerly or the southerly direction.

- The price impacts of this exercise of market power are smaller than in South Australia (although the practice appears to be more frequent than in South Australia).

- The QLD spot price seldom reaches high levels during this exercise of market power – mostly falling in the range $30-$300/MWh.

- In addition, as we will see below, this market power occurs almost exclusively at times of relatively tight supply-demand balance in the QLD region.

Rather than just focusing on specific examples, let's now turn to explore all the episodes of market power over the present financial year.

3.3 Further study of the exercise of market power in QLD

Figure 43 below shows the extent of withholding by just five QLD generating stations – Millmerran, Callide C, Callide, Tarong North and Gladstone – during the recent summer (November 2009 – February 2010). As can be seen, the exercise of market power in QLD is seldom the action of a single generator. In almost every case, three or four generators are withholding simultaneously. Figure 43 also reveals a close correlation between the patterns of withholding and the peak demand (net of interconnector flows) on each day, which is further explored in Figure 44.

Figure 43: Withholding in QLD 1 November 2009 - 28 February 2010

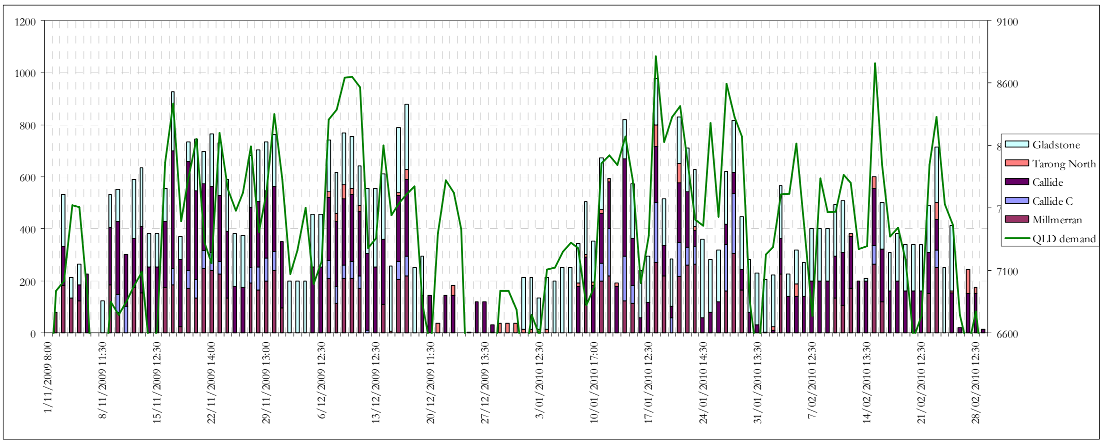


Figure 44 shows the correlation between peak net demand in QLD (demand less imports) and the extent of withholding by these five generators over the present financial year (since 1 July 2009). Again, the correlation between the volume of withholding and the peak demand is clear. It appears that these generators do not price much capacity above $9000/MWh until demand exceeds around 7200 MW. For demand above 8000 MW these generators are withholding around 400 MW on average.

Figure 44: Volume withheld versus peak QLD net demand 1 July 2009 - present

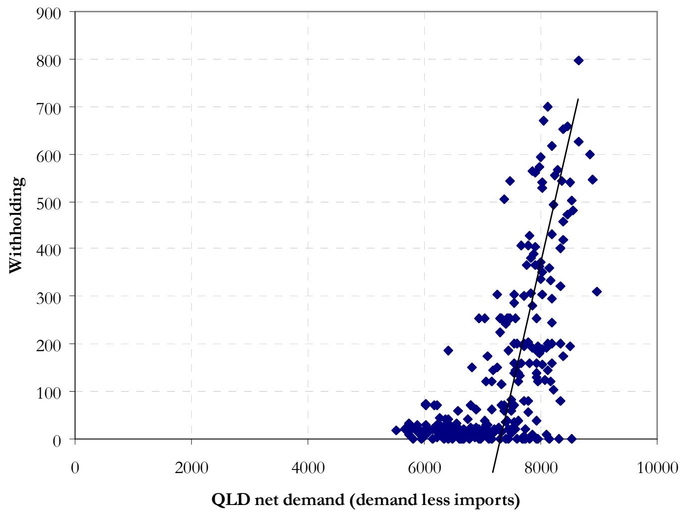


Figure 44 shows that these five generators in QLD tend to engage in market power at times when the net demand in QLD is high. In fact, further investigation shows that of the 66 days in the past financial year on which the peak demand in QLD exceeded 7800 MW, the four generators Millmerran, Callide C, Callide, Tarong North engaged in economic withholding on 68% of these days. On a further 23% of these days, although the net demand in QLD was high, the interconnector flow was sizeable and in the direction of NSW, with prices equalised between the two regions. On these days a substantial withdrawal of capacity would be required to reverse the flow on the interconnector, to achieve a higher price in QLD. This leaves just six days. On one of these days, although the flow was at its limit into NSW, the price in NSW was low ($34/MWh) which was probably not high enough to justify any withdrawal of capacity in QLD. Finally, on five other days, the conditions seem to have been suitable for these generators to exercise market power, but, for some reason, on these Gladstone power station was not withholding at all (Gladstone conventionally withholds around 200 MW of capacity at peak times). It seems that for some reason, the coordinated withdrawal of capacity between these four generators and Gladstone was not achieved on these days.

This note did not seek to estimate the impact of this exercise of market power on the wholesale spot price in QLD (this analysis was carried out by IES in the work commissioned by the AER). As a rough guide, we might speculate that without the exercise of market power, the QLD price would fall to the NSW price or, where the QLD price is lower than the NSW price, the QLD price would be less than or equal to $50/MWh. If this were the case, the volume weighted average peak daily price would drop from $43/MWh to $30/MWh. The effect on the overall average price would be somewhat smaller.

3.4 Conclusion

The exercise of market power in QLD seems to involve repeated, coordinated interaction of a number of generating companies, particularly at high demand times in QLD, and particularly when constraints bind on the NSW-QLD interconnector. As suggested in chapter 1, this coordination does not require the existence of any explicit (and certainly not a written) arrangement. It might be possible to achieve a degree of coordination of this kind through the mechanism raised in chapter 1 – that is through a market-sharing arrangement where each generator seeks to achieve and defend a given market share at all times. As noted in chapter 1, this would require an "interleaving" of the offer curves of the generators. But this is only one possibility.

There is an open question whether the pattern of interlocking shareholdings in QLD facilitate coordinated interaction of this kind. As we have seen, certain generators in QLD (such as Callide C) are jointly owned by firms which also compete independently with their own generating units.

This raises the question whether or not joint ownership of a power station might facilitate coordination across a region.

On any one episode this market power seems to have had a much smaller impact than the exercise of market power in SA. Seldom does the wholesale spot price in QLD reach the market price cap. However, as already noted, this exercise of market power is more frequent than the exercise of market power in SA and therefore it is not possible in the abstract to state whether or not the impact on the average wholesale spot price in QLD is smaller than the impact of market power in SA.

This study has focused on detecting patterns in the exercise of market power in the wholesale energy market in SA and QLD. It is possible that market power is also being systematically exercised in other regions of the NEM (such as NSW), or by other generators (such as Snowy Hydro), or in other markets (such as the FCAS markets in Tasmania). However, detecting such market power would require further analysis which is left for future research.

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