NATIONAL GENERATORS FORUM

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

Dear Mr Pierce

NATIONAL ELECTRICITY AMENDMENT (POTENTIAL GENERATOR MARKET POWER IN THE NEM) RULE 2011 – DIRECTIONS PAPER

The National Generators Forum welcomes the opportunity to comment on the Commission's proposed approach in relation to the Potential Generator Market Power in the NEM Rule change request, as set out in the Directions Paper released in September 2011.

The NGF is the national industry association representing private and government owned electricity generators. NGF members operate all generation technologies, including coal-fired plant, gas-fired plant, hydroelectric plant and wind farms. Members have business interests in all States.

Overall approach

The NGF supports the broad approach proposed by the Commission. We believe that the Commission's analytical framework of taking a longer term perspective in defining and assessing market power, applying the standard of a 'workably competitive' market, considering spot and contract prices and of focusing on substantial and sustained market power represents a sound and workable approach.

The NGF considers that the overall approach outlined by the Commission minimises the risk of unwarranted market intervention, and is likely to be consistent with the NEO's focus on efficient investment for the long term benefit of consumers. We highlight that regulatory intervention to constrain prices in the wholesale market fundamentally risks undermining the ability of generators to recover their efficient fixed costs and the capacity of the market to attract and sustain sufficient future generation investment.

The NGF recognises that the task of assessing and attempting to measure the extent of any substantial market power, which may have a detrimental effect on the efficiency of the NEM, is an inherently difficult exercise. Like all reviews of this nature, the AEMC will ultimately need to form a considered judgement about whether to proceed to any further stage of the Rule change based on a range of information and associated data.

The Commission's Directions Paper asks for comment on the proposed approach it intends to take at the next stage of Review. To help us to consider the proposed assessment framework, the NGF commissioned SFS Economics to provide an expert view on the methodology outlined in the Directions Paper and NERA report. Given that the Directions Paper asked for comment on the proposed approach, the SFS report focuses on the challenges the Commission will face in undertaking an assessment of this kind.

The NGF supports the Commission doing some work along the lines of the framework outlined in the Discussion Paper. However, the Commission should be fully aware of the alternative approaches and the limits of such an exercise. The analysis of markets and market power can never be reduced to a simplistic analysis and we are sure that the Commission will fully consider industry reasoning and debate when assessing the merits of the Rule change proposal.

If the Commission holds substantial doubt about the merits of the MEU proposal at the end of the next stage, we believe it would justify a decision to move straight to a Draft Determination instead of prolonging the period of uncertainty for new investors as to a key aspect of market design.

Average price versus LRMC component of the market power test

While the NGF is supportive of the broader approach adopted by the Commission, we are concerned that the 'average price versus LRMC' component of the market power test described in the Directions Paper is not conceptually sound, and will incorrectly identify the existence of generator market power in a range of circumstances where this is not the case.

The key conceptual issues that arise in the application of the average price criterion are that[1]:

- In order to reflect a meaningful investment standard (as intended by the Commission), an LRMC – price comparison would need to consider post-entry prices, rather than historical prices.
- The LRMC standard assumes a standard NPV investment criterion. This criterion is not valid in circumstances where there is considerable uncertainty about future market outcomes, investment projects are largely sunk and where investments can be postponed, as is generally the case for generation investment in the NEM.

The average price component of the market power test will therefore tend to confirm the existence of market power when wholesale prices do not support new investment.

We also consider that a number of serious issues arise in the implementation of the average price criterion in practice:

- The calculation of LRMC involves forecasting least cost expansion paths for the electricity system and is inherently complex and dependent on assumptions.
- There is no single agreed methodology for calculating LRMC. Each of the different methods commonly applied will produce different LRMC estimates.
- For any particular method of calculating LRMC, many factors will affect the outcome of a calculation, resulting in a wide range of estimates in practice.

The resulting uncertainty of an LRMC calculation therefore risks undermining the reliability of any market power determination made on that basis.

[1] The NGF notes that the Commission's Directions Paper indicates that it will consider both wholesale market prices and any contract price data it is able to obtain when carrying out its analysis. For the purposes of this submission we refer to spot prices when discussing average prices to simplify the discussion. Spot price references should be interpreted as a reference to the likely mix of spot and contract data in the Commission's analysis.

More generally, it is important to recognise the impact of real events on the relationship between wholesale market prices and the LRMC standard. Wholesale market prices exhibit a great deal of short-term variability from external factors which are independent of any generator bidding strategies. These factors do not feature at all in an LRMC calculation. They include a wide range of external factors, including the drought, transmission outages, interconnector operating procedures and many others.

We believe that the two to three year time horizon for the application of the market power test should be extended to at least five years. Both transmission and generation investment have significant lead times, not just for the construction of the project, but also to complete site and easement acquisitions, as well as planning and approval processes.

Barriers to entry criterion

The NGF supports the Commission's approach to consider the structural characteristics of the market to assess future competitive trends, as reflected in the 'barriers to entry' component of the market power test. However, we believe that there are a number of additional factors that are also relevant in the context of assessing generator market power, and that the Commission should consider in any market power assessment:

- countervailing power from customers, such as the ability of retailers to dispatch peaking plant to mitigate against high price outcomes;
- countervailing power from retailers and/or customers arising from demand side responsiveness; and
- the extent of actual and potential import competition, including interconnectors that may be commissioned under the regulatory test;
- the dynamic characteristics of the market, such as whether future demand growth is likely to encourage new entry.

Market definition

We do not think that the application of a 'SSNIP' test combined with a 5 per cent threshold represents a sound approach for defining the geographical boundaries of the 'market' in which market power may be exercised. Given limited interconnector capacity in the NEM, the test will very likely determine a regional market structure, irrespective of which region is analysed. A precise 5 per cent threshold also seems at odds with the very large discrepancies between the prices that different NEM models typically predict. These uncertainties would potentially undermine the credibility of a market definition exercise.

Summary

We would like to reiterate the point that the NGF supports the Commission's overall assessment framework for the Rule change and the general market definitions outlined in the Discussion Paper. We are very cautious, however, to provide a full endorsement of the modelling approach and proposed approach for identifying the market dimensions in the Discussion Paper due to the complexity, extent and importance of external factors.

The stated intention of the Directions Paper is to seek industry comment on the proposed assessment framework. While we raise a range of issues with NERA's methodology, the NGF supports the key aspects of the Commission's approach to date.

About the consultants

Sabine Schnittger

Sabine Schnittger is an experienced economist with deep expertise in market design and regulatory issues arising in energy markets in Australia and internationally. Sabine has advised the AER on barriers to entry in the South Australian region of the NEM and the New Zealand Ministry for Economic Development in relation to market power in the New Zealand electricity market. She has worked on a number of competition assessments of Australian electricity and gas markets, as well as other industry sectors, and is currently assisting the ACCC on forced tying arrangements in the bulk handling of grain.

Dr Brian Fisher

This paper was peer reviewed by Dr Brian Fisher, a respected adviser on the energy and resources sectors. Brian previously held the position of Executive Director of the Australian Bureau of Agricultural and Resource Economics, as well as senior government positions. Prior to heading up ABARE, Brian was Professor of Agricultural Economics at the University of Sydney and became Dean of the Faculty of Agriculture at the University in 1987. He was appointed Adjunct Professor of Sustainable Resources Development in 2003.

Yours sincerely

Peter Shields

Chair, NGF Markets Working Group

17 November 2011

SFS ECONOMICS

POTENTIAL GENERATOR MARKET POWER IN THE NEM – Comments on the AEMC Directions Paper

NOVEMBER 2011

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AEMC Directions Paper – Potential market power in the NEM

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

The Australian Energy Market Commission (the Commission) has published a Directions Paper that sets out the Commission's proposed approach for defining market power in the National Electricity Market (NEM). We have been asked by the National Generators Forum to review the Directions Paper, and to set out any identified shortcomings and areas for improvement.

THE COMMISSION'S OVERALL APPROACH

The Directions Paper considers in some depth the various views expressed in the Commission's earlier consultation on generator market power, as well as international precedents and the broad themes set out in the literature on this issue. The Commission's considerations address a number of 'threshold' issues, which form the basis for the broader approach that the Commission intends to apply. That overall approach represents a sound and workable framework that takes account of the specific characteristics of the electricity supply industry. The Directions Paper then establishes the following basic criteria that the Commission will apply in a market power assessment:

- a longer term perspective in defining and assessing market power;
- a competitive standard that emphasises a 'workably competitive' market, rather than a (hypothetical) perfectly competitive market; and
- the use of spot and contract prices; and
- a focus on substantial and sustained market power, rather than on transitory price spikes.

These criteria recognise the important role of (short term) spot prices in signalling supply scarcity, as well as the complexities of analysing individual price events, and minimise the risk of unwarranted market intervention. As such, the Commission's overall approach is likely to be consistent with the National Electricity Objective (NEO), in particular the focus on efficient investment for the long term benefit of consumers.

This approach is consequently a pragmatic approximate one for the complex task of assessing the level of market power. This paper provides a discussion of some of the issues with the approach which are presented as a positive contribution to the debate for consideration by the Commission.

FORMULATION OF THE 'SUBSTANTIAL' MARKET POWER CRITERION

Given this overall approach, the Commission intends to define what constitutes 'substantial' market power with reference to price outcomes and structural characteristics of a market. The Commission's market power test consists of two components:

- the ability to increase annual average wholesale prices to a level that exceeds long run marginal costs (LRMC) over some timeframe; and
- that ability to increase prices is due to the presence of significant barriers to entry.

The Commission intends to define the geographical boundary of the (antitrust) market in which market power is thus exercised by assessing the ability of a hypothetical monopolist controlling all generating capacity in a region to raise prices by 5 per cent (the 'SSNIP' test).

AVERAGE WHOLESALE PRICE VERSUS LRMC CRITERION

Intervention in an energy-only market such as the NEM brings with it material risks for the longer-term viability of the market, in terms of the ability of the market to attract new investment. Therefore any rule that would trigger such intervention must be conceptually sound and capable of reliably identifying substantial market power if and when it occurs.

The average price component of the proposed market power test is derived from the theoretical proposition that, in the long run, efficient prices should approach LRMC. Average wholesale prices that exceed LRMC for some length of time should trigger new investment. If no investment occurs, it is possible to conclude that the relevant market is not workably competitive.

While this line of reasoning may be correct in theory, there are a number of reasons for thinking that a comparison of average wholesale market prices with LRMC is not a meaningful or reliable tool for identifying market power in the context of an electricity wholesale market.

First, the fact that (historical) average wholesale market prices may exceed LRMC does not imply that new generation investment is profitable:

- Annual average wholesale market prices necessarily reflect *past* price outcomes. Past prices are not relevant for deciding whether an investment is worthwhile. What matters instead is whether *future*, *post entry* prices will suffice to recover the cost of the investment. Given that new generation investment will tend to depress future prices, average wholesale market prices will need to exceed LRMC, possibly significantly, before an investment becomes viable.
- The mismatch between the theoretical test and an investor's approach. The LRMC standard assumes that investors undertake a standard (static) net present value (NPV) calculation (so that the present value of future revenues exceeds the present value of costs). Such an NPV investment criterion is no longer valid where there is uncertainty about future market outcomes, investment projects are irreversible and sunk, and investments can be delayed. These characteristics generally apply to generation investment in the NEM. In these circumstances, there is an

option value attached to waiting, and it is often optimal to postpone the timing of new investment.

As a result, the average price test will tend to confirm the existence of market power when wholesale spot prices do not support new investment. This effect may be particularly pronounced in smaller regions of the NEM where the capacity of an additional generation plant may be large relative to the existing capacity in the region (and post entry prices will therefore be materially lower).

Second, in practice, the calculation of LRMC is complex and, as noted elsewhere by NERA, 'an inherently uncertain exercise'. In a complex system such as the NEM, the (Turvey) method for calculating LRMC proposed by NERA will likely entail a comparison of two separate multi-period system optimisations, rather than simply calculating the cost of completing a given capacity expansion one year sooner than would otherwise be the case. There are also a number of different methods for calculating LRMC in practice, including the Turvey (PWISC) method, the 'textbook' long-run incremental cost (TLRIC) method and the average incremental cost (AIC) method; each of these methods produces different LRMC estimates. Finally, for any particular method, many factors will affect the outcome of a calculation, including the choice of demand increment and the planning horizon. As a result, there can be little confidence that the 'right hand side' of the average price component of the market power test has been estimated correctly.

Third, it is unclear whether a workable relationship between spot market prices and the LRMC standard exists. Spot market prices exhibit a great deal of short-term variability, which will also affect longer term price averages, but do not feature in an LRMC calculation. Regardless of generator bidding strategies, many factors will have a material impact on prices, including the recent drought, transmission network outages, interconnector operating procedures and many others. More generally, capital-intensive process industries such as electricity generation share some common characteristics that can create prolonged supply-demand imbalances and investment cycles, and pronounced price swings over time. Individually and in combination, these factors will tend to obscure the relationship between average wholesale market prices and LRMC over anything but a very long time horizon.

The Commission proposes to apply the market power test over a period in which new (generation or transmission investment) can be expected to occur, and has said that this period is likely to be at least two to three years. A period of two to three years is too short a timeframe over which new investment can be commissioned; a five-year timeframe is likely to be more appropriate. Both transmission and generation investment have significant lead times, not just for the construction of the project, but also to complete planning and approval processes. In addition, the specific characteristics of generation investments in an energy-only market imply that investors have a strong incentive to delay investments beyond the timing suggested by a simple NPV criterion.

MARKET DEFINITION

Making a market power determination requires clarifying in which market that market power is exercised. The proposal is to determine the geographical (regional or NEM-wide) boundaries of the market by applying a 'SSNIP' test. That test would ask whether a hypothetical monopolist of all generating capacity in a NEM region could increase the average regional spot price in that region over a one to two year period by 5 per cent above LRMC.

It is not clear whether the application of the SSNIP test, as described by the Commission, is particularly suited to defining the geographical boundary of an electricity market. On the face of it, and given limited interconnector capacity in the NEM, it would seem likely that the outcome of the test will be to cause each region to be a market as a foregone conclusion.

A more fundamental difficulty with the application of a precise SSNIP test arises because it relies on electricity market models for modelling strategic behaviour on the part of generators. Price predictions made by such models are inherently ambiguous, in the sense that they are often artefacts of assumptions that have been made about particular bidding and other parameters. Indeed a comparison of past modelling exercises undertaken in the NEM suggests a remarkable degree of variation in wholesale market price predictions. A 5 per cent price threshold as a basis for defining the boundaries of the relevant market would seem to be well within the margin of variation of different NEM models, and it is difficult to see what precise conclusion can be drawn from one model versus another.

BARRIERS TO ENTRY CRITERION

The Commission proposes that the average price criterion will be accompanied by an assessment of whether there are barriers to entry that prevent new entrants from investing in the relevant market.

Barriers to entry, properly defined, are a standard tool in merger competition assessments. Given the uncertainties associated with any detailed wholesale market modelling exercise and the LRMC calculation, it is sensible to focus on the structural characteristics of a market as a way of assessing future competitive trends.

There are a number of additional factors that are also relevant in the context of assessing generator market power, and that should be considered:

- the extent of actual and potential import competition, including interconnectors that may be commissioned under the regulatory test;
- countervailing power from customers, such as the ability of retailers to dispatch peaking plant to mitigate against high price outcomes;
- countervailing power from retailers and/or customers arising from demand side responsiveness; and

- the dynamic characteristics of the market, such as whether future demand growth is likely to encourage new entry.

CONCLUSIONS

The Commission'proposed approach of focusing on a workably competitive electricity wholesale market and on a 'substantial' market power criterion is sound and consistent with dynamic efficiency objectives. The focus on underlying structural and competitive attributes of a market, as reflected in the 'barriers to entry' component of the market power test, is also consistent with this approach.

However, the average price versus LRMC component of the proposed market power definition suffers from a number of serious conceptual flaws and will likely be both complex and contentious in its implementation. At a minimum, average prices would need to be adjusted for a range of extraneous factors, considered over a longer term time horizon, and separately assessed as to whether such prices would support new investment. LRMC estimates would similarly need to be evaluated for their robustness with respect to differing assumptions and approaches for calculating them. Given the many complexities inherent in such calculations, it seems unlikely that such an analysis would deliver definitive results. This risks undermining the credibility of a market power determination made on that basis.

In summary, the AEMC approach represents a pragmatic approach to an intractable problem. The use of LRMC compared to average spot and contract prices is a reasonable test for assessing whether there is a problem and whether to proceed to a more detailed analysis.

1. INTRODUCTION

On 22 September the Australian Energy Market Commission (Commission) published a Directions Paper that sets out the Commission's proposed approach to defining market power in the NEM. The Directions Paper addresses a Rule change request submitted by the Major Energy Users Inc. (MEU), which alleges that market power is a significant concern in the NEM, and argues for the imposition of price controls.

In the Directions Paper the Commission sets out that it intends to adopt a longer-term perspective for the purposes of identifying and measuring market power. The Commission also proposes to adopt a number of recommendations made by NERA in a report prepared for the Commission (the NERA report). The key elements of the Commission's proposals are:

- a definition of what constitutes market power in the NEM that focuses on a comparison of LRMC with average wholesale prices in combination with the existence of barriers to entry; and
- a definition of what constitutes the relevant geographical market for the purposes of applying the market power definition that focuses on the ability of a hypothetical monopolist within a NEM region to undertake a SSNIP (a 'small but significant and non-transitory increase in price').

1.1. TERMS OF REFERENCE

We have been asked by the National Generators Forum to undertake a critique of the Directions Paper in order to identify any shortcomings in the Commission's proposed approach and areas where the Commission could improve its proposed assessment framework. Specifically the critique should provide advice on:

- the Commission's market power test, including the practical implications that will arise in the application of the LRMC and average wholesale price standard;
- the 'barriers to entry' criterion proposed by the AEMC; and
- the relevant definition of the 'market' for the purposes of the Rule change.

1.2. ABOUT THIS REPORT

This report is structured as follows. Section 2 comments generally on the risks of intervening in energy-only markets. Section 3 critiques the Commission's proposed definition of substantial market power. Section 4 discusses the proposed SSNIP test to establish the geographical boundaries of the market. Section 5 comments on the matters that should be considered in an examination of structural aspects of a market.

2. THE COMMISSION'S DIRECTIONS PAPER

The focus of the Directions Paper is on developing a definition for market power in the NEM that would then form the basis for its market power assessment and any consequent changes to the Rules. The Directions Paper also touches ona number of other matters, including the longer term consequences of intervention in an energy-only market such as the NEM.

2.1. INVESTMENT INCENTIVES IN ENERGY-ONLY MARKETS

The Commission notes that occasional price spikes are an inherent feature of electricity wholesale markets, and has therefore elected totake a longer-term approach when defining and assessing market power in the NEM. The Commission also acknowledges that regulatory intervention to constrain prices is likely to deny at least some generators the opportunity to recover their efficient fixed costs, and thereby puts future investment at risk.

These considerations fundamentally go to the longer-term viability of the NEM, in terms of the ability of the market to attract and sustain sufficient future generation investment. The energy-only market design of the NEM does not incorporate payments for generator capacity or availability. In general, generators must recover the fixed cost of plant from differences between market clearing prices, as represented by the price duration curve (PDC), and variable generating costs.

It is generally acknowledged that even in a perfectly competitive market, price spikes that incorporate 'scarcity rents' are necessary to enable generators to recover costs(Stoft, 2002).[1]Market interventions such as the MEU's proposed administered price caps (or any other form of price regulation) that are designed to dampen or eliminate higher priced periods will change the price duration curve and therefore impair longer-term investment incentives.

Deregulated power markets are complex, and it can be difficult to separate the effects of scarcity from market power, however defined. However, it is not the case that price spikes based on high generator bids necessarily imply that such bids exceed short run marginal costs (SRMC). Most generators have continuous marginal cost curves, including an emergency operating range above nominal maximum output level where marginal costs increase dramatically (Stoft, 2002; Ruff, 2002). It is always possible to operate above some measure of full capacity, at least for a while, by paying overtime, sacrificing some technical efficiency, overstressing equipment or delaying maintenance at the risk of more costly repairs later. This means that for any particular generating facility, the SRMC curve continues for some distance beyond the normal output range, becoming infinite where no additional output can be produced from the facility.

[1] Scarcity generally refers to a situation where the demand curve intersects the supply curve on the (near) vertical section close to maximum output. Under these conditions, generation capacity is scarce and earns 'scarcity rents' – the excess of revenue over SRMC.

Determining SRMC is therefore far more complex than simpler and more conventional measures of marginal costs such as average fuel costs and variable operation and maintenance (O&M) costs would suggest.[2] This is particularly the case when a facility is operating at or near its full output and may have to take costly measures to increase output slightly.

2.2. PRICE INTERVENTION RISKS

The adverse impacts of regulatory measures designed to suppress high prices are compounded by the absence of other price signals that capacity is scarce. In theory, efficient market-clearing spot prices in electricity wholesale markets should reflect the opportunity costs of actions taken by the system operator to maintain system stability in situations where demand is high relative to supply (Ruff, 2002). Efficient prices should then reflect not just suppliers' SRMC, but also the implicit costs of demand interruptions, low operating reserves, temporary overloading of elements of the transmission network or voltage drops, or risky system operations more generally. In practice, in most, if not all markets, the dispatch software only calculates market-clearing prices from the offer prices of dispatched generators; other factors are not taken into account.

The fact that SRMC are both very difficult to determine in practice and that the determination of market-clearing prices does not generally account for scarcity increases the risks associated with market intervention. Overall, and as set out by Ruff (2002), forcing spot scarcity prices below competitive market-clearing levels will reduce the efficiency of the market and increase total costs to consumers in the long run. Administrative procedures for controlling prices are generally arbitrary and therefore wrong much of the time. Given the difficulty of knowing when spot prices are above competitive market-clearing levels, the high costs and risks of trying to reduce prices, and the low payoff even if market intervention is done well, price intervention is not merited unless there is clear evidence of harm to the wider market.

[2] This is quite aside from the difficult intertemporal calculations that have to be performed to determine opportunity costs where there are fuel constraints.

3. SUBSTANTIAL MARKET POWER TEST

The Commission's proposed test to identify 'substantial' market power consists of two components, namely that annual average wholesale prices must exceed LRMC over some timeframe, and that average prices must be higher than LRMC due to the presence of significant barriers to entry. This section focuses on the price versus LRMC component of the market power definition.

3.1. LRMC AS AN INVESTMENT CRITERION

NERA's recommendation that market power should be defined by comparing annual average wholesale prices with LRMC is derived from the theoretical economic literature, which posits that in a long run equilibrium, efficient prices should approach LRMC. Thus it is postulated that:

- when demand is below capacity, competition drives spot prices below LRMC to equal the SRMC of the marginal producer; and
- when capacity is scarce, prices rise above LRMC to clear the market until new capacity comes online.

NERA note that generation investment takes place in discrete implements (is 'lumpy') so that there will be some periods of 'misalignment' when there is an excess or a shortage of capacity. However, in a workably competitive electricity wholesale market, prices that are significantly and persistently above LRMC should, in time, prompt a supply-side response (NERA 2011, P.22ff.). One indication therefore that a generator (or group of generators) has a substantial degree of market power is when average spot prices exceed the LRMC of adding new capacity.

As we set out in the following, NERA is mistaken in thinking that average wholesale market prices that exceed the LRMC standard should trigger new investment (and that therefore such prices are indicative of generator market power). The average price versus LRMC criterion:

- conflates historical wholesale market prices with post-entry prices;
- fails to recognise that when investments are irreversible and future market outcomes are uncertain, standard NPV rules no longer apply; and
- assumes that system LRMC, rather than a technology/plant-specific LRMC is the relevant cost benchmark for investors.

As a result, the market power test proposed by NERA will incorrectly identify the existence of generator market power in a range of circumstances when this is not the case.

3.1.1. HISTORICAL PRICES VERSUS POST-ENTRY PRICES

The Directions Paper emphasises that the pricing aspect of the proposed market power definition is intended to be consistent with conventional market forces that will cause wholesale electricity prices to rise as capacity shortages become more likely (AEMC P.30):

> '.. *a firm has substantial market power if it has the ability to sustain prices that should attract new investment because they exceed LRMC, ..*'.

This characterisation of the market power test is not correct, however. As defined, it implies a comparison of *historical* annual average price outcomes with a calculated LRMC standard for those years. If historical prices are found to be higher than the LRMC standard, the presumption is that these prices should support new investment (and that there is market power).

In reality, an average price criterion that focuses on historical prices will not support future investment. What matters instead are whether *post entry* prices will be sufficient to recover the cost of the investment. In an energy-only market, an investor contemplating a generation investment would look first at the PDC in the relevant region. The shape of that curve is central to determining whether future prices will be sufficient to recover the cost of different types of generation technologies of a particular size. What is moreover crucial is not the current height and shape of the PDC, but its height and shape *post entry*. Given that generation investment tends to be 'lumpy', commissioning a new generation plant will likely lower market clearing prices, particularly in the smaller NEM regions. A rational investor will take this into account, so that the fact that historical prices may have exceeded LRMC is not relevant. Generation investment will only take place if expected *post-entry* (rather than *actual*) prices are greater than LRMC over some longer-term timeframe.

The average price test will therefore tend to confirm the existence of market power when wholesale spot prices do not support new investment. As set out in the following, this effect is likely to be more pronounced because of the specific characteristics of generation investment, which imply that standard (NPV) investment rules are not appropriate.

3.1.2. IRREVERSIBLE INVESTMENT UNDER UNCERTAINTY

Under a standard NPV investment criterion, a firm can expect to profit from adding capacity when the present value of expected total revenues from the new capacity equals or exceeds the present value of total costs. This investment dynamic is consistent with prices fluctuating around LRMC over some given timeframe. However, an NPV criterion is no longer valid in circumstances where there is significant uncertainty about future states of the world, and where investment projects have two key characteristics:

- investments are irreversible, so that any expenditures must be viewed as sunk; and
- investments can be delayed, for instance, to wait for new information about prices, costs, and other market conditions before expenditures are committed.

Irreversibility makes the payoffs from an investment especially sensitive to various risks, including uncertainty about future prices (Dixit and Pindyck, 1994). Where there is significant uncertainty, the possibility of delaying an investment is therefore much like a financial call option. Such an option gives the holder the right to pay an exercise price and in return receive some type of asset that has some value. When a firm makes an irreversible investment expenditure, it exercises, or ‘kills’, its option to invest. It relinquishes the possibility of waiting for new information that might affect the value or timing of the investment. The expenditure cannot be reversed if market conditions change adversely; this lost opportunity cost of investing must be included as part of the cost of the investment. The key point is that the NPV rule ‘invest when expected revenues are at least as large as the costs of the investment’ no longer applies in these circumstances. The value of the investment must exceed its costs by an amount equal to the value of keeping the option to invest elsewhere alive – the opportunity cost of investing.

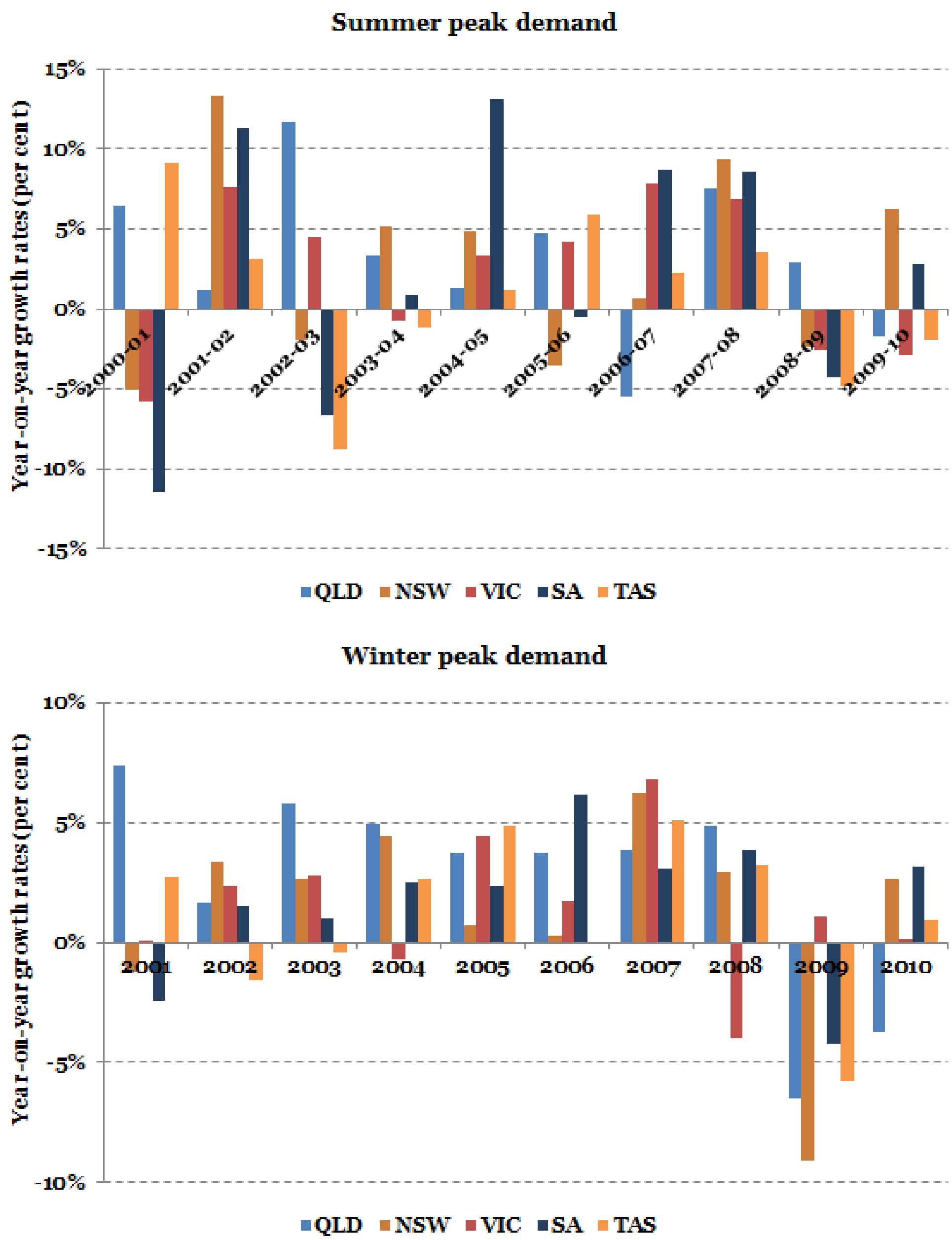
Generation investment in deregulated power markets such as the NEM has these characteristics. Generation investment is generally irreversible; once made, an investment cannot be redeployed and the costs are sunk. Furthermore, electricity demand, which is one key driver of spot prices, is intrinsically difficult to forecast. Electricity demand is driven by weather conditions, technological evolution and business cycles, and year-on-year changes and associated implications for prices are very difficult to predict (Neuhoff, 2004). This is especially the case for extreme values of demand and price distributions such as high demand days and associated price spikes.

There are correspondingly a number of studies of the effect of demand and other types of uncertainties, and their implications for the timing of generation investment. Botterudand Korpås (2004) for instance, use a case study of a new gas plant in the Norwegian electricity market, to show that an investment rule that ignores the option to delay an investment is not optimal. Once short-term uncertainty and fluctuations in the spot price are taken into account, the optimal investment strategy in an energy-only market becomes significantly more restrictive than would be the case under a static NPV evaluation:

- the timing of the investment decision is postponed, relative to what would occur under an NPV rule; and
- investment only occurs after average spot prices have reached a level that is considerably higher than the total unit cost of the plant.

Considerable uncertainty about future demand and price outcomes is also a feature of the NEM. Figure 3-1shows the extent of variability in annual load growth for the various regions of the NEM over the past ten years. Uncertainty about future load growth is only one of a number of risks that investors would consider before committing to undertake an irreversible generation investment. Other risks would include uncertainty about future regulatory and government policies, for instance those impacting on the penetration of renewables (wind) in the NEM and the associated impact on prices.

FIGURE 3-1. REGIONAL YEAR-ON-YEAR DEMAND VARIABILITY



Notes: Summer peak average growth rates (standard deviations) are – Queensland, 3.2% (4.9%); NSW, 2.7% (6.0%); Victoria, 2.2% (4.9%), SA, 2.2% (8.2%), Tasmania, 0.8% (5.2%). Winter peak average growth rates, (standard deviations) are – Queensland, 2.6% (4.4%); NSW, 1.3% (4.2%); Victoria, 1.5% (2.9%), SA, 1.7% (3.0%), Tasmania, 1.2% (3.3%).

Source: AEMO/NEMMCO Statement of Opportunities 2003, 2006, 2011.

3.1.3. SYSTEM-WIDE VERSUS GENERATOR SPECIFIC LRMC

As defined by NERA, the LRMC standard relates to '*the cost of serving an incremental change in demand in a market*' (p.51), and gives rise to time-dependent fluctuations in LRMC. As such, any LRMC estimates will be an amalgam of various cost components across the system, including the costs of operating existing generation plant more frequently, as well as the cost of commissioning and running new plant.

The system LRMC standard described by NERA is not the same as the LRMC of building and operating an additional unit of a particular generation technology, which would feature in an NPV (including option value) calculation. That (plant-specific) LRMC would be expected to change relatively slowly, as capacity, fuel and other cost evolve over time. It is therefore unclear how a system-wide LRMC estimate would be relevant to investors considering investing in a specific generation technology.

The distinction is described by Intelligent Energy Systems (IES, 2004) who were commissioned by IPART to determine the LRMC of electricity in NSW. IES describe the calculation of a system LRMC along the lines outlined by NERA; that is, the marginal increase in system costs associated with meeting an incremental increase in demand. IES set out that this definition is not consistent with the guiding principles for setting retail tariffs in New South Wales, which requires default levels to be set at levels that broadly match the supply cost of new generating capacity. Where there is excess capacity, as was the case in New South Wales in the form of partially utilised coal units and interstate capacity, the calculated LRMC would have been low relative to the full costs of generation for many years. IES therefore elected to calculate LRMC on the basis of the new entry generation required to meet a forecast load profile at lowest cost.

3.2. THE LRMC STANDARD

As discussed above, NERA propose a system-wide (market) LRMC standard, this being an estimate of the forward looking optimised cost of serving an additional increment of load. However, NERA mischaracterise the method of calculating LRMC that they advocate, and do not refer to the different methods that are applied in practice to estimate LRMC, as well as the considerable uncertainties that attach to such an exercise.

3.2.1. MARGINAL INCREMENTAL COST STANDARD

NERA's method for calculating LRMC reflects an approach advocated by Professor Ralph Turvey in the context of the new approaches to utilities (in particularly water) regulation then being developed in the United Kingdom. This method is variously referred to as the 'perturbation' or Present Worth of Incremental System Cost (PWISC) method. Calculating PWISC (as defined by Turvey) involves:

- postulating a (hypothetical) small increase in demand/output over some defined planning horizon;[3]

[3]Turvey refers to ".. permanent output increment which is postulated as being large enough to be noticeable but small enough to be marginal" (Turvey 1969, P.288).

- calculating the difference in present values (PVs)of system costs with and without the demand increment; and
- dividing this cost difference by the difference in PVs of the corresponding output increments.

NERA say that LRMC as defined by Turvey can be determined relatively simply, by calculating the cost associated with undertaking a given capacity expansion (one year) sooner than would otherwise be the case in response to the incremental change in demand (NERA 2011, p.5). However, this is not generally true. Turvey (1976, 2000) explains that this method of calculating LRMC is only a shortcut, as it avoids the complexities of multi-period system optimisations, which an LRMC calculation normally requires(Turvey 2000, p.9ff.):

> *However, it cannot be assumed that this will always be the case, since the optimal adjustment of plans to a postulated increment or decrement lasting only one or a few years may be more complex than simply advancing or retarding the construction of one new lump of capacity. It can be demonstrated, using the simple model expounded above, that there are cases where adjustment to a postulated increment or decrement changes the optimal order in which such new lumps are added to the system.*

For a complex system like the NEM, calculating PWISC is therefore not straightforward, requiring a comparison of two optimised demand/investment scenarios.

3.2.2. OTHER LRMC STANDARDS

Turvey's method for calculating LRMC (as described by NERA) is only one of a number of methods that have been developed and applied in utility pricing over the years. There is no single agreed approach in the economic literature about how LRMC should be defined and calculated.

All methods for calculating LRMC have in common that they consider only forward-looking costs and assume that investment is optimised. Within that broad framework, however, there are significant methodological differences, and indeed differences between how different authors describe a particular approach.[4]Mann et al. (1980) describe the key methodologies as follows:

- the PWISC (Turvey) method calculates the relative incremental system costs of a permanent increment in demand and does not generally look beyond the next investment;
- the 'textbook' long-run incremental cost (TLRIC) method calculates the relative incremental system cost of the next planned capacity expansion, and also does not look beyond the next large investment; while

[4]Indeed Turvey's own descriptions of his approach varies in different papers, in terms of how capital costs are accounted for.

- the average incremental cost (AIC) method calculates the incremental cost of meeting future demand growth relative to current demand over a longer-term planning horizon.

Which method is appropriate in the present context is not obvious, but will matter a great deal in practice because different methods imply different price paths, which would in turn imply different market power thresholds. Table 3-1, which reproduces various LRMC estimates of the costs of Sydney Water calculated by NERA, illustrates this point. The range of LRMC estimates presented reflect changes in key assumptions, including in relation to the change of the assumed demand increment and the timing of its application in the context of the planning horizon.[5]It is apparent that:

- LRMC estimates differ depending on whether the Turvey or the AIC method is chosen; and
- LRMC estimates made under both the Turvey and the AIC method are quite sensitive to changes in the underlying assumptions.

TABLE 3-1. SUMMARY OF ILLUSTRATIVE LRMC ESTIMATES (SYDNEY WATER)

Method	LRMC, $/kl (2007/08 dollars)[1)]
Turvey approach	1.39 – 2.13
AIC approach	1.84 – 3.36
IPART estimate	1.90 / 2.37[2)]

Notes: 1) NERA note in a footnote to this table: "Our illustrative Turvey estimates are sensitive to the size and timing assumed for the increment/decrement used in the analysis and should not be relied on as an estimate of the LRMC in the absence of a proper review of the least cost forward capital expenditure Program to equate demand and supply."

2) IPART estimates differ depending on which portion of desalination plant costs are deemed avoidable.

Source: NERA (2008), p.15.

The results shown in Table 3-1 are indicative of a more general finding that different methods for calculating LRMC imply material differences in terms of the levels of estimates, the extent of variability over time, and the extent of cost recovery. Other variants of LRMC methods additionally reconsider the existing capital stock. Frontier Economics (2008) explain that in estimating the LRMC of electricity supply, existing generation plant can be treated in different ways:

- 'Greenfields' LRMC assumes that there is currently no plant available to meet demand, and that demand must be met using an entirely new generation system that is least cost. This approach therefore re-prices all existing capacity at efficient levels.

[5]NERA note that the assumptions used for these calculations were necessarily made without rigorous examination of Sydney Water's investment plans.

- 'Brownfields' LRMC assumes that the existing mix of generation plant in the system is in place, and that demand can be met using both existing and new generating plant. This approach therefore focuses on the least cost expansion path for the system as it stands today.

Many other factors will affect the outcome of any particular calculation. Overall, and as noted by NERA (2008, p.10), '*In practice, estimating LRMC is an inherently uncertain exercise*.' NERA note that in practice LRMC estimates will be affected by the methodology used, as well as the accuracy of forecasts of future demand and the associated least cost investment program. Specifically where the PWISC (Turvey) approach is concerned, LRMC estimates are highly sensitive to the choice of increment or decrement in demand, both in terms of the size of the increment and the timing of its application in the context of the planning horizon.

3.3. AVERAGE WHOLESALE MARKET PRICES

NERA set out that there is a strong 'in principle' link between SRMC (and therefore spot market prices) and LRMC over the long term. While market imperfections may mean that the timing of capacity expansions will not always be perfect (NERA, 2011, p.8):

> '.. *provided that the concepts are measured over a sufficiently long timeframe, the link between SRMC, LRMC and new investment decisions should mean that, on average, there is no material difference between the value of SRMC and LRMC.*'

Whether this theoretical finding translates into a workable relationship between wholesale market prices and the LRMC standard, even if prices are highly averaged, is questionable, however:

- prices in electricity wholesale spot markets are affected by many factors on a day to day basis that do not feature in an LRMC calculation; and
- more generally, capital-intensive process industries such as electricity generation share some common characteristics that can create prolonged supply-demand imbalances and large price swings over time.

3.3.1. FACTORS AFFECTING AVERAGE WHOLESALE MARKET PRICES

The Australian Energy Regulator's (AER's)annual 'State of the Energy Market' reports describe in some detail the many and various factors that have impacted on prices over a year in all regions of the NEM, including extremely high temperatures, generator limitations and outages, network outages, flooding, and other incidents. Some of the most material events that occurred in recent years and had an impact on wholesale market prices regardless of any generator bidding strategies include (AER, 2007-2010):

- *A persistent drought over the past decade that materially affected dispatch and power flows between 2006 and 2009.*The drought constrained hydro-generating capacity in the Snowy, Tasmania and Victoria, and also limited the availability of water for cooling for some coal-fired generators in New

South Wales and particularly in Queensland. Imports to South Australia fell and required a significantly increased reliance on gas-fired generation. Victoria similarly significantly increased its reliance on gas-fired generation, including from significantly increased LNG use. Historically low hydro storage levels in Tasmania resulted in Tasmania becoming a net energy importer from 2006.

- *High temperatures and bushfires (7-8 February 2009)*. Extremely high temperatures and bushfires in Victoria (45°C), in NSW (41°C) and in South Australia (39°C) reduced transmission network capability in Victoria, led to a lack of Reserve (LOR) 3condition in Victoria, the loss of transmission lines in New South Wales, as well as the loss of Basslink and consequent tripping of Tasmanian generators.

- *Significant planned and unplanned transmission outages*. These include:

  - a prolonged transmission outage at Gin Gin (13 June 2007), which accounted for significant congestion in Queensland during 2006-07, and limited dispatch of central and northern Queensland generators by as much as 550 MW; and

  - the Western network upgrade in New South Wales, which, in combination with drought constraints, affected the dispatch of NSW power stations between December 2009 through to August 2010.

- *Interconnector performance*. Instances where NEM interconnectors are operated below nominal transfer ratings and/or where circular flows occur are persistent, with consequences for spot market prices. In November 2009, for instance, and during a combined (temperature driven) high demand day and generator outage in New South Wales, flows to New South Wales were significantly reduced as a result of network constraints elsewhere. Cheaper generation in Victoria and South Australia could not be dispatched to replace expensive generation in New South Wales and Queensland, resulting in very high prices in New South Wales and Queensland, and negative prices in Victoria, South Australia and Tasmania.

- *Demand and supply trends in fuel markets*. Changes in the availability of key fuels such as gas will feed through into future electricity wholesale market prices. In Queensland, for instance, the rapidly growing supply potential of coal seam gas has seen new entrant gas plant benefiting from low priced ‘ramp gas’, although longer term expectations are for significantly higher gas prices that are likely to approach export parity.

These factors appear sufficiently material to obscure a longer term relationship that exists in theory between prices and LRMC. Moreover, even prolonged events such as the drought or serious transmission limitations are unlikely to induce new generation investment, given that investors will expect these events to be resolved over the foreseeable future. Arguably an application of the Commission’s market power test involving average wholesale market prices and an LRMC standard would require these factors to be accounted for in such a calculation.

3.3.2. RELATIONSHIP BETWEEN AVERAGE WHOLESALE MARKET PRICES AND LRMC

Capital-intensive process industries such as electricity generation share some common characteristics that make these industries prone to persistent supply-demand imbalances:[6]

- *Lengthy lead times*. As discussed in Section 3.4, lead times for planning and commissioning new generation and transmission capacity are lengthy. Commissioning transmission investments can take three to five years; for generation assets, lead time are three years for CCGT technologies and longer for other types of technologies.

- *Irreversible expenditures under uncertainty*. As set out in Section 3.1, new generation requires significant investment expenditures to be incurred in circumstances where future demand is uncertain. Once made, investment are also sunk. In these circumstances, it is often more profitable to delay investment until uncertainty about future market outcomes is at least partially resolved. Wholesale market prices therefore need to rise beyond LRMC to make an investment viable, possibly significantly so.

- *Lumpy investment under uncertainty*. Because generation investments are based on uncertain forecasts, capacity additions may turn out to be 'too small' or 'too big' relative to realised demand.

Individually and in combination, long lead times, forecasting errors and lumpy investment can combine to cause substantial and prolonged mismatches between capacity and demand, and corresponding long run variations around a longer run price equilibrium. These effects have been studied for a number of industries, including for the electricity industry:

- Gross et al. (2007) describe long run (years to decades) investment dynamics that arise in competitive electricity markets. Because it takes several years to bring new power plant online, investment in response to rising prices requires some judgement in advance of likely impending shortfalls in the market. Given significant price risks, which translate into significant uncertainty about future investment returns under different scenarios, investors willrequire large discount rates, effectively driving average -run prices higher than would be the case without uncertainty.

- Finon (2004) and Simshauser (2001) also describe long-run cyclical investment patterns in electricity. They point to anecdotal evidence from a number of deregulated electricity markets, including in Queensland, England and Wales, and North America, where investment was encouraged by recurrent high price episodes, but where uncoordinated investment decisions then lead to an oversupply of capacity and subsequent material and sustained price falls. Causal factors identified by Simshauser include overly optimistic

[6] Other capital-intensive process industries with similar characteristics are primary metals, cement and chemicals manufacturing; as well as petroleum refining.

electricity demand forecasts, high (pre-entry) spot prices, economies of scale, and first mover advantages.

- Ford (1999) investigated the nature of generation investment cycles using a simulation model of the western United States, assuming that new plant would be built on the basis of future price projections, and taking into account permitting and siting delays. That model also predicted that the construction of new generation occurs in cycles over an approximately 10 year timeframe, with associated significant price oscillations over time. The simulations also highlighted that:
  - in many circumstances, investment patterns in generation can be characterised as an inherently unstable; and
  - investment and price volatility increases with higher construction costs, given the price incentives needed to trigger an investment.

3.4. RELEVANT TIME HORIZON

The Commission proposes that the relevant period over which average prices should be compared with LRMC estimates should reflect the period over which new entry from a range of possible technologies, including generation and transmission investment, can be expected to occur (in the absence of significant barriers to entry). The Commission states that this period is likely to be at least two to three years (p.13).

However, a timeframe of two to three years is likely to be too short a timeframe over which new transmission and generation investment can be commissioned:

- As set out below, both transmission and generation investments require significant lead times, not just for the construction of the project, but also to complete planning and approval processes.
- In addition, the specific characteristics of generation investments in an energy-only market, namely that investment expenditures tend to be substantial, that investment is irreversible, and that there is considerable uncertainty about future market outcomes (as well as government policies), investors have a strong incentive to delay investments. These factors mitigate against a prompt investment response as a result of high prices.

The risk is therefore that higher average prices over one or two years will prompt a market power investigation and potential intervention. This risk can be expected to be greater in smaller regions of the NEM where the size of new investment relative to the size of the market may amplify price swings.

3.4.1. TRANSMISSION INVESTMENT

For transmission assets, the time to construct and complete a particular asset or set of assets will depend on the scale and complexity of the project, and can range from several months to years. More importantly, planning processes for such assets are very lengthy. Significant transmission investments such as interconnectors must complete extensive approvals processes, which take a number of years(Table 3-2):

- Regulatory investment test for transmission (RIT-T) approval processes require at least one year, provided a dispute is not invoked before the AER; and
- provided that the investment is approved, transmission network service providers must then complete a number of local and state planning and consultation requirements; and
- TNSPs must also identify and obtain easement corridors, which may take a number of years to complete.

Augmentations of interconnectors may additionally require these processes to be undertaken in parallel by TNSPs in different states with the associated potential for delays.

TABLE 3-2. TRANSMISSION APPROVAL PROCESSES PRIOR TO IMPLEMENTATION

PROCESSES	REQUIREMENTS
RIT-T approval processes	- Stage 1: Initial project specification report for review and publication by AEMO, with an associated public consultation period of no less than 12 weeks. - Stage 2: Assessment of public submissions, preparation of draft project assessment for review and publication by AEMO with an associated public consultation period of no less than 6 weeks. - Stage 3: Assessment of submissions and meetings with interested parties, subsequent preparation of final assessment report. - Possibility of challenge before the AER, which must make a determination between 40 to 100 business days.
Local/state planning	Land acquisition processes Easement establishment and compensation processes Statutory planning/permitting requirements by local councils/state government Environmental impact assessments, including flora and fauna study; archaeological and cultural assessment; noise studies; electromagnetic field (EMF) assessments Public consultations with councillors, members of parliament, landowners &the wider public

Source: AER (2010).

A recent report by the Victorian Electricity Distribution Businesses(2010) on planning processes for transmission connections, for instance, concluded that the lead-time required for (intra-regional) transmission asset augmentations, while dependent on the number of interdependent activities involved in the project, varies from between three to five years. That report identified some of the timeframes involved in commissioning transmission connection projects, for instance:

- a period of at least 24 months to obtain a planning permit in relation to the proposed works; and
- a lead-time of 24 months for delivery of connection assets such as terminals as a consequence of high demand for these items worldwide.

3.4.2. Generation investment

Commissioning new generation investment similarly requires significant lead-times. ACIL Tasman (2009) suggest that the lead time for development of combined cycle technologies is around three years; with the exception of open cycle turbines, all other technologies require longer lead times. If significant new transmission works or fuel (gas) infrastructure are required, investment lead times may correspondingly be longer.

A recent report prepared for Commonwealth Minister for Resources and Energy suggests that ACIL's estimates of lead times may in fact be optimistic (Investment Reference Group Report, 2011). That report identifies nine stages that must be completed before a greenfield CCGT can begin commercial operations (Table 3-3), and an overall timeframe of more than 72 months (Figure 3-2).

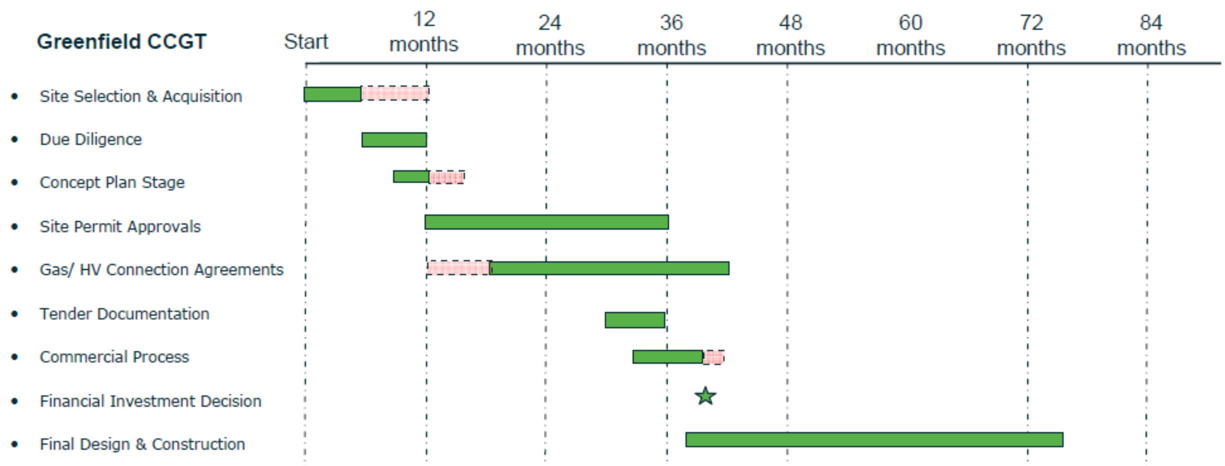
Table 3-3. Stages from site selection to commissioning for CCGT power stations

Development stage	*Key tasks*
1. Site Selection & Acquisition	- Location of suitable sites, negotiation with landowners - Execution of commercial agreements
2. Due Diligence	- Detailed due diligence on site to identify and mitigate any potential major impacts on further developing the site (physical connections, site contamination, noise etc.)
3. Concept Plan Stage	- Development of preliminary design configurations, plant outputs and plans that will feed into development applications
4. Site Permit Approvals	- Assessment of the project including environmental, social and technical impacts covering power generation and associated infrastructure (i.e. including gas pipeline and HV transmission lines) - Documentation of impacts in permit documents including Environmental Effects Statement (EES) concluding with issuance of development consent and key works approvals
5. Gas/ HV Connection Agreements	- Detailed technical studies supporting successful application for gas pipeline licence and HV electrical connection agreement (including acquisition of easement access corridors)
6. Tender	- Development of all required technical and

Documentation		commercial documentation to allow tendering of plant items to suppliers
7. Commercial Process	-	Issuance of tender documents, tender period, evaluation, analysis, negotiations and internal approvals for EPC, GSA, GTA and project financing requirements to support a Financial Investment Decision
8. Financial Investment Decision	-	Date of board approval that will allow construction of project to proceed
9. Final Design & Construction	-	Encompassing site preliminary works (Pre-FID) and actual construction and commissioning of project to Commercial Operation Date

Source: Investment Reference Group Report, 2011.

FIGURE 3-2. TIMELINE FOR CCGT GREENFIELD DEVELOPMENT



Source: Investment Reference Group Report, 2011.

3.5. SCOPE OF THE AVERAGE WHOLESALE PRICE VERSUS LRMC CRITERION

It is unclear how the Commission intends to apply the average price versus LRMC market power definition.

The wording of the definition suggests that all that may be necessary for the market power criterion to be met is a likely ability to sustain high wholesale prices, rather than necessarily any actions to that effect. This seems consistent with the Commission's statement that (p.18): '*The Commission .. proposes that regulatory intervention is only potentially justified if there is evidence that generators have exercised, or are likely to exercise, substantial market power*'.

Elsewhere, the Commission says that the wording is intended to clarify that it is not necessary to wait for several years of above-LRMC pricing before taking action (p.20).Rather, if a generator has caused annual average wholesale prices to exceed LRMC and there are significant barriers to entry that will constitute evidence of the exercise of substantial market power. There are therefore two alternative interpretations of what the Commission intends to achieve:

1. Market power can be deemed to exist if a generator *is likely* to cause wholesale prices to rise above a certain level (even if the generator has not taken any actions to that effect in the past); or

2. Market power can be deemed to exist if a generator has in the past increased wholesale prices and is expected to do so again in the future.

The distinction between the actual or possible exercise of market power, however defined, is important. The Commission's own review of regulatory approaches in relation to market power, both as it is formulated in the *Competition and Consumer Act 2010*and as regards legal precedent overseas, makes it clear that merely possessing substantial market power is not prohibited. What matters instead is whether the relevant party has taken advantage of its market power for an anti-competitive purpose. The Commission's definition therefore raises two concerns:

- First, the likelihood that a generator has market power as a rationale for intervention represents a departure from well-established legal precedent. If the market power definition is interpreted in this way, it defines far broader circumstances as to when regulatory intervention is merited than is the case in other markets.

- Second, in either case (i.e. if there is a mere likelihood or if there is some evidence of past price manipulation and an expectation that this may continue), the definition then raises questions as to the substance of the one to three year time horizon. Specifically, a finding that a particular generator had acted to increase average wholesale prices over some shorter timeframe would seem to be sufficient to launch an investigation to consider the existence of barriers to entry and consequently possible market intervention. On that interpretation, higher than LRMC prices in any one year would suffice to trigger a market power investigation.

As it stands, therefore, the market power definition requires further clarification as regards:

- whether the intention is to capture only instances where a generator has demonstrably taken some actions to raise average wholesale market prices above LRMC, or whether the intention is to capture a broader set of circumstances where a generator is deemed by the regulator to be likely to do so; and

- if the second interpretation is intended, how the one to three year time horizon proviso would be applied, given that any intervention would be prospective.

4. MARKET DEFINITION

A determination that a particular generator has market power in a particular market first requires identifying the 'boundaries' of that market in which competition takes place. The Commission proposes applying a hypothetical monopolist or 'SSNIP' test that is used in competition assessments to determine the relevant geographical boundary of the market (p.22):

> *NERA's proposed application of the SSNIP test starts by assessing whether a hypothetical monopolist of all generating capacity in a NEM region could increase the average regional spot price in that region over a one to two year period by 5 per cent above LRMC.*

As explained by the Commission, the key question is therefore whether or not current interconnector capacity allows generation in other NEM regions to prevent a hypothetical monopolist from profitably implementing a SSNIP.

The application of a SSNIP test is a commonly used tool in conventional merger assessments to identify the most immediate competitive constraints faced by a firm or group of firms. As this test is generally applied, its focus is on demand-side substitution as the main competitive constraint, specifically consumers' preferences regarding price and product attributes.[7]

There are a number of ways in which the SSNIP test can be operationalised in practice. One of these is 'critical loss analysis', which seems to correspond to the Commission's description of how this test would be applied. Critical loss analysis considers market participants' cost structures and relevant product demand elasticities to calculate whether a firm would profit by raising prices of product X by 5-10 per cent, or whether substitution to other products would 'defeat' the price increase, i.e. make the price increase unprofitable. In the context of market power in the NEM, the application of the SSNIP test would therefore entail a market modelling exercise.

4.1. HYPOTHETICAL REGIONAL MONOPOLIST

It is not clear whether the application of the SSNIP test, as described by the Commission, is particularly suited to defining the geographical boundary of the relevant (antitrust) market. In a conventional analysis, say, for the supply of gasoline in Sydney, establishing the geographical boundaries of the market would be done by asking whether a hypothetical monopolist in Sydney could profitably increase prices by x per cent. The question would then be whether consumers would or could substitute gasoline from competitors outside Sydney, say in New South Wales, and thus defeat the price rise. If the answer is yes, the geographical market would be broadened to New South Wales and the exercise would be repeated by sequentially expanding the boundaries of the market.

[7] An analysis of supply side substitution is generally limited to focusing on whether firms can switch capacity to produce demand-side substitutes.

In the context of an electricity market, this chain of substitution does not practically exist. Although (large) customers may have become more responsive to high prices, there is no product substitute for electricity, certainly in the short run. Electricity demand must be met instantaneously, so that there is no possibility of importing cheaper electricity and storing it for later use. Perhaps most importantly, and as noted by AEMO (2010), while the NEM transmission network comprises strong regional transmission networks, cross-border transmission capabilities are modest. Given the size of existing interconnections in the NEM, therefore, the assumption that a hypothetical generator monopolist controls all generation capacity in any one region will almost certainly lead to a regional market definition.

It could therefore be argued that a SSNIP test applied to the NEM is not particularly meaningful, and does not fit well with the empirical realities of the market. In this context it is interesting to note that a SSNIP analysis was not undertaken in the Loy Yang case (AGL v ACCC, 2003) where the question of the geographical boundary of the market was analysed. In that judgement, the focus was instead on the degree of price separation and the incidence of constraints between regions, the ability of retailers to hedge inter-regional price exposures, and the degree of substitution between generators in different regions. The Australian Competition and Consumer Commission (ACCC) also notes in its Merger Guidelines (2008) that while the hypothetical monopolist test is a useful tool for analysis, it is rarely strictly applied to factual circumstances because of its onerous data requirement. Consequently, the ACCC will generally take a qualitative approach to market definition.

4.2. Numerical (5 per cent) threshold

A fundamental difficulty with applying a precise SSNIP test using electricity market models arises because any price predictions on the basis of such models are inherently ambiguous.

A great deal has been written about different theoretical approaches to modelling wholesale power markets, in particular about predicting price outcomes when generator offers exceed SRMC. Generally speaking, the dynamics of electricity markets are modelled within a game theoretical framework whereby generators are assumed to submit bid functions in a repeated game.[8] These models essentially try to predict strategic games on the basis of a range of assumptions, including about the nature of strategic interactions. Equilibrium prices and quantities are found by identifying Nash equilibria – that set of participant offers such that no participant can improve its profit by unilaterally deviating from the offer.

The difficulty that arises both in theory and in practice is that electricity market models predict multiple equilibria in many circumstances. This makes it very difficult to draw general conclusions about market outcomes beyond the specific

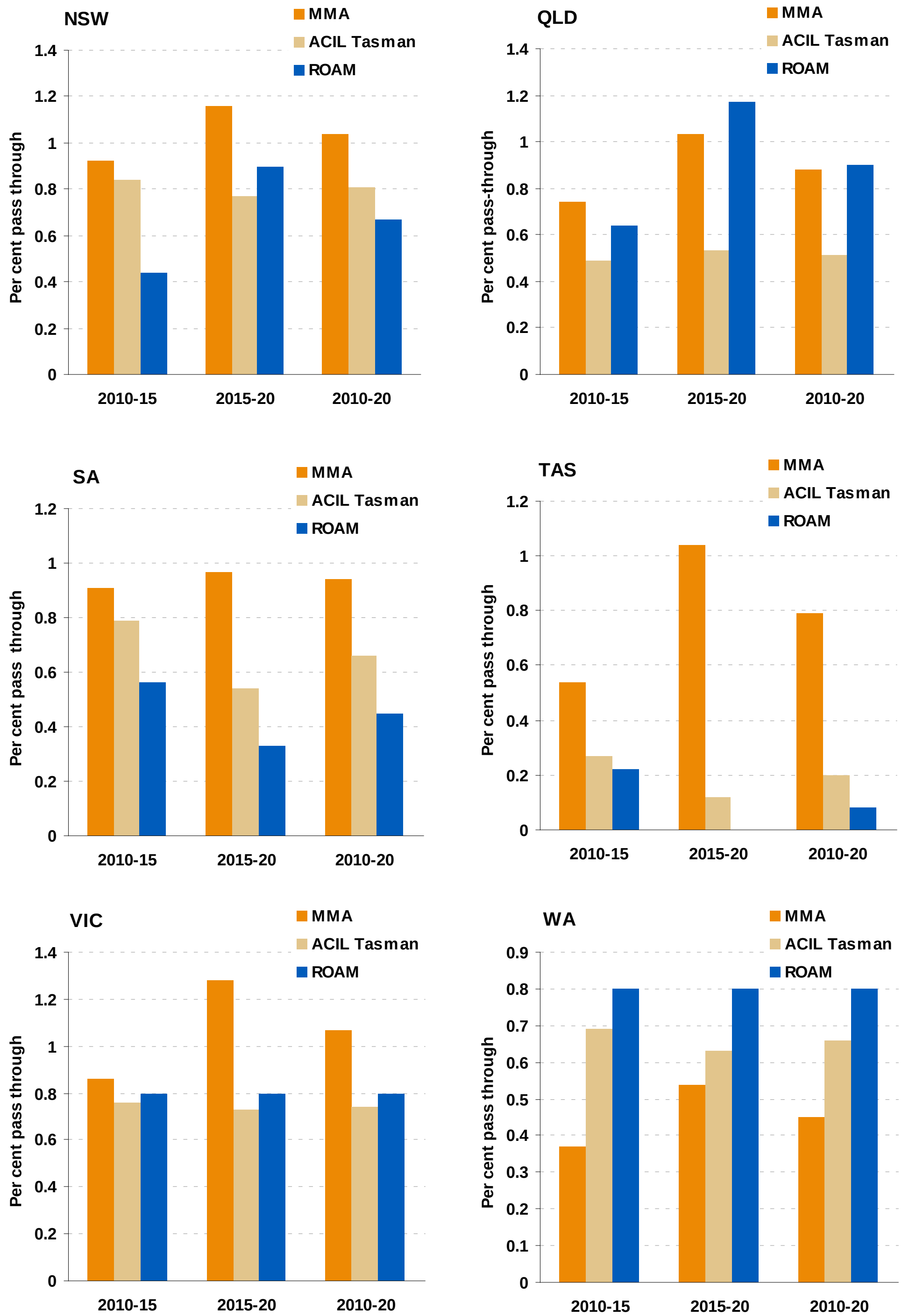
[8]Within that broader framework, there are different classes of models, including Cournot, Bertrand, and supply function equilibrium models.

scenarios analysed, but it also reduces the predictive value of such models, in terms of their ability to forecast spot market prices. In practice, the problem may be overcome by constraining the range of possibly solutions in some manner, for instance, by limiting the range of bidding strategies available to each individual generator. Hence, while electricity market models can model and predict the circumstances where there might be generator market power, the precise numerical price predictions are often artefacts of assumptions that have been made about the choices of particular bid parameters (Baldick; 2002, 2007). More generally, necessarily complex models of an electricity spot market incorporate a large number of parameters and modelling assumptions that will also affect the results.

Figure 4-1 below illustrates this issue with reference to modelling undertaken on behalf of the Commonwealth Treasury (2008) to assess the likely price implications of a carbon price. Forecast wholesale market prices depend on the extent of pass-through of the carbon price, which is in turn a function of the pricing power of individual generators. Figure 4-1 highlights that there was no consistent view between models as to the extent of any future price rises. For instance, over the period 2010-15, ROAM estimate that wholesale market prices in New South Wales would increase by less than half (44 per cent) of the price of emissions permits, while ACIL Tasman estimated wholesale price increases of 84 per cent of permit prices and MMA projected a 92 per cent price pass through.

The implication of these modelling ambiguities is that they raise serious questions as to whether NERA’s proposed application of a SSNIP test is likely to be robust. A 5 per cent price threshold as a basis for defining the boundaries of the relevant market would seem to be well within the margin of variation of different NEM models, and it is difficult to see what precise conclusion can be drawn from one model versus another.

FIGURE 4-1: COMPARISON OF AVERAGE WHOLESALE PRICE PROJECTIONS – EXTENT OF CARBON PRICE PASS THROUGH



Notes: CPRS targeted to achieve emissions reductions of five per cent below 2000 levels by 2020 and 60 per cent below by 2050.

Source: Australian Government, 2008.

5. BARRIERS TO ENTRY

The second component of a market power assessment is the presence of 'barriers to entry'. The Directions Paper does not define barriers to entry, but notes that the Commission will address this question during later stages of the process.

5.1. CONSISTENT APPLICATION

Broadly speaking, barriers to entry refer to factors that make it more difficult for an 'outsider' than for an existing 'insider' to enter the market. 'Structural' barriers to entry refer to circumstances where new entrants into a market have to incur additional costs that incumbents do not face (or have not had to incur in the past). 'Dynamic' barriers to entry are defined more broadly and refer to factors that will substantially delay and possibly eliminate new entry.

Barriers to entry are a standard tool of merger assessments, but the term is nonetheless often misunderstood. Taken on their own, for instance, the need to make significant (sunk cost) investment (as is the case in the electricity industry) is not a barrier to entry. Indeed, there are many industries that require significant firm- or industry-specific investments as a condition of entry. Given that electricity wholesale market prices must be sufficiently high *post entry* to make new generation investment viable, high prices are also not an indication of barriers to entry (although, of course, high prices may be a consequence of barriers to entry). This term therefore needs to be clarified and applied in a consistent way.

5.2. OTHER RELEVANT FACTORS

Given the uncertainties associated with any detailed modelling exercise, including LRMC calculations, it is sensible to focus on the structural characteristics of a market as a way of evaluating future competitive trends. However, an assessment of barriers to entry is only one way of assessing the competitiveness of a market. There are a number of additional factors that are typically considered in competition assessments, and that are also relevant in the context of assessing market power in a wholesale electricity market, including (ACCC 2008):

- the extent of actual and potential import competition;
- countervailing power from customers; and
- the dynamic characteristics of the market.

5.2.1. ENERGY IMPORTS AND THE RIT-T

In the present context, import competition refers to competition from interstate generators over existing and proposed interconnectors. A focus on import competition also highlights the relevance of the RIT-T as a less intrusive mechanism for addressing inefficiencies arising from the exercise of market power than intervening in the market.

The AER's most recent (2010) guidelines to the application of the RIT-T explain in detail that the calculation of market benefits '.. *includes competition benefits where the modelling process explicitly takes into account the likely impact of the credible option on the bidding behaviour of generators (and other market participants) who may have a degree of market power* ..' (AER 2010, P.70). The framework and processes for applying the RIT-T in the NEM have been refined over a number of years to ensure that, as far as is practically possible, the decision to undertake a transmission investment is taken where a material net benefit can be identified. Moreover, transmission augmentations, if merited, do not entail the serious longer-term risks to investment that are a consequence of regulatory intervention in the market.

5.2.2. COUNTERVAILING POWER BY CUSTOMERS

As a general rule, electricity demand from consumers is price inelastic, at least in the short term, so that consumers are not in a position to respond to high prices by reducing consumption. However, where retailers purchase electricity on behalf of consumers, other factors may also come into play. For instance, there is some evidence that peaking units owned and operated by NEM retailers are occasionally dispatched at offer prices that are not necessarily reflective of SRMC and are instead designed to lower regional spot prices. In these circumstances, the ability to dispatch plant would point to meaningful countervailing power by retailers.

Perhaps more importantly, the recent evidence suggests that customers may be becoming increasingly responsive in managing their exposure to high spot prices:

- In its current review of demand side participation (DSP), the Commission sets out empirical and anecdotal evidence which suggests that there is a material level of DSP, including (AEMC, 2011):
  - an AEMO survey, which identified 719MW of DSP available in 2010, of which 131 MW was committed;
  - AER investigations into high price events that identified evidence of probable demand response at times of high prices, for instance, an apparent demand reduction of up to 265 MW in New South Wales following a price spike of over $6 200/MWh on10 August 2010;
  - the application of DSP solutions by distribution and transmission networks;
  - anecdotal evidence that major industrial users engage in DSP where usage of the plant/equipment may be reduced or even completely switched off in response to high wholesale electricity spot prices.
- The Electricity Supply Association of Australia (ESAA, 2011), in its submission to the DSP consultation, quotes a comprehensive analysis of the impact of dynamic pricing on reducing peak demand in Australia and internationally. The study showed that such pricing had in trials reduced average peak demand by between 4.7 per cent and 34.1 per cent depending

on various factors. According to the ESAA, a number of market participants are trialling dynamic pricing schemes, including Ergon Energy, Energex, OriginEnergy, AusGrid, AGL Energy, and the Victorian distribution businesses.

- The Energy Users Association of Australia has recently been quoted as saying that a recently observed decline in peak summer demand may reflect price responsiveness of industrial and domestic customers who have cut consumptionand changed electrical fittings (Lawson (Australian Financial Review), 2011).

5.2.3. DYNAMIC MARKET TRENDS

While past behaviour can be relevant for drawing conclusions about likely future market outcomes, a market power assessment is fundamentally a forward-looking exercise. As such, future (dynamic) market trends should also be considered to determine whether any identified issues will persist. In this context, expected demand growth is of key importance, since whether a market is growing or declining can have significant implications for its competitiveness in the future (ACCC 2008). Rapidly growing markets may offer both greater scope for new entry and the erosion of market shares over time (and vice versa). An example of such an effect might be the commissioning of the US$30 billion Olympic Dam expansion project in South Australia, which may in turn attract new investment for the project's associated electricity requirements.

All of the above factors are material in an assessment of whether substantial market power, however defined, is likely to persist in the future. Barriers to entry are a key indicator of the structural competitiveness of a market, but a complete competition assessment should consider the full range of other indicators that are typically assessed.

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