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Evaluating interconnection competition benefits

FINAL REPORT

PREPARED FOR THE AUSTRALIAN COMPETITION AND CONSUMER COMMISSION

September 2004

Final

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The purpose of this report is to test whether a workable method for estimating competition benefits can be developed in the context of the regulatory test. The focus of this paper is on the approach rather than the realism of the example used to test the approach.

The workability of the approach for measuring competition benefits has been tested on the SNOVIC 400 project. SNOVIC 400 was a 400 MW augmentation of the existing interconnect between Snowy and Victoria that *has already been built*. This augmentation raised the transfer capacity from the Snowy region to the Victoria region from 1,500 MW to 1,900 MW. This augmentation does not normally increase the transfer capacity from Snowy into NSW however – that is, only the southern flow transfer capacity has been improved from this augmentation.

The development of an interconnect will change the way the existing stock of plant will be used and could also change the pattern of investment compared to the situation where the interconnect was not developed:

- **Changes to the dispatch and pricing of existing plant (static benefits):** Increased competitive pressure from a new or enhanced interconnector is likely to dampen generators' ability to raise prices above costs in the importing region (if the market is not already perfectly competitive). At the same time the same interconnector may enhance the ability of generators in the exporting region to raise prices. Either way, the interconnector could alter bidding behaviour which could alter the dispatch of plant. Whether or not the overall market is better off, in terms of lower cost dispatch and lower prices, which supports greater economic activity, is an empirical question, and is the subject of this study. For the purposes of this study we have termed this form of 'competition benefit' as being the ***static benefits***. This is because these benefits are concerned with making more efficient use of *existing* inputs. The fact that these benefits are called 'static' does not necessarily infer that they are enjoyed only in the short term. Indeed, the pro-competitive bidding and dispatch effects of a new or enhanced interconnector would be expected to continue into the longer term.
- **Changes in investment patterns (dynamic benefits):** To the extent that an interconnector makes the generation market more competitive, this may have an effect on the timing, size and location of investment in new generators. For example, an incumbent generator with a degree of market power may decide to invest in new capacity *earlier* than an independent investor, in order to entrench its market position. The incumbent may choose to make a short-term loss on the new capacity by building new capacity early in order to avoid a larger loss that may result from a new competitor building the plant and eroding incumbent market power. This pre-emptive investment represents a waste of the community's resources. With a new or enhanced interconnector the generator may no longer be able to profitably engage in this type of behaviour. This may cause generators to build generators closer

to the most optimal pattern in terms of when, where and how much capacity, and of what type. This represents a saving of resources in the longer term.

This study is concerned with developing and applying a framework for measuring the ***static*** competition benefits of interconnects. Projects that are rejected on the basis that they do not produce significant net static benefits may produce net dynamic competitive gains. However, if the benefits from the static analysis are not significant, this is likely to suggest that the benefits arising from dynamic analysis are also likely to be small and, hence, the value of undertaking a dynamic analysis may be limited. This is because the impacts of competition on investment are only likely to be significant if the first-round impact on prices is significant.

Measurement of the dynamic competition gains are outside the scope of this analysis. Overlooking these dynamic gains is only likely to be a problem where the static competition gains are significant, but not large enough to justify an construction or augmentation of an interconnect. Disregarding the dynamic gains is not likely to be a problem where the static gains are insignificant (since the dynamic gains are also likely to be insignificant and their inclusion is unlikely to justify the project) or where the static gains are large enough on their own to justify a project.

A pre-augmentation base case was developed for each option focussing on one year, 2004/05 (the limited time-frame available for study precluded modelling over more years). Under the SNOVIC *modelling* base case, the Snowy to Victoria interconnect constrained south for about 45 hours of the year, indicating the potential for material market benefits from augmentation.

Given these estimated incidences of constraints the SNOVIC augmentation was, unsurprisingly, estimated to yield significant net benefits - in the order of $40 million *for one year,* under the assumption that demand for electricity is responsive to price changes (i.e. elastic). Under the assumption of inelastic demand (that is, the competition benefits are confined to the savings in generation costs because of changes in generator bids that result in lower cost dispatch), the benefits were estimated to be around $4m for a single year.

This exercise has highlighted the difficulty in estimating competition benefits. In spite of these difficulties the framework presented in this report shows that there is workable approach for measuring competition benefits. For example, the model produces intuitively sensible results in that prices move the right way and the orders of magnitude of benefits are consistent with expectations. For example, where the base case modelling showed that the interconnects were relatively unconstrained, there was little benefit in augmenting its capacity and vice versa when constraints were material.

Given the generally positive results of this exercise (in terms of demonstrating the workability of the approach and the intuitively sensible results) we believe that a more detailed analysis of the assumptions is warranted. This more detailed assessment would aim to ensure the estimated benefits are not overly sensitive to key assumptions and would allow a more considered calibration of the base case assumptions to ensure they are broadly in line with expectations in relation to price levels and frequency and severity of transmission constraints. In the meantime, the results of this analysis should be used cautiously.

Introduction

1 Introduction

1.1 BACKGROUND

In the National Electricity Market (NEM) if a participant wants to build a new interconnect or augment an existing one, and they wish the costs of this to be recovered through regulated grid prices, they have to conduct a so-called "regulatory test" to show that it is economically net beneficial. One of the benefits that can be ascribed to a new or augmented interconnect are the "competition benefits" that may result from the investment.

In simple terms the transmission competition benefit is the value of extra economic activity resulting from any reduction in electricity price that can be directly attributable to the augmentation and any cost savings because generators are bidding in a way that results in more efficient dispatch. Additional interconnection can cause electricity prices to fall for two reasons:

- it allows cheaper generating plant to displace the production by more expensive plant; and
- it reduces the opportunity of certain generators to charge prices above their costs of production.

To date, competition benefits have not been explicitly included in the analysis of the net benefits of interconnects in the NEM for two main reasons:

- the other (non competition related) benefits of the interconnects have been more than large enough to justify the cost of these projects; and
- competition related benefits are much harder to calculate than the other economic benefits from interconnection.

However, it is important that a robust technique be developed to measure and compare the competition related benefits of new and augmented interconnects for two key reasons:

- the original intent of the NEM was to develop arrangements to facilitate the development of (regulated) interconnects to promote competition between the State electricity systems and yet, to-date, the competitive impacts from interconnection have been ignored; and
- as the power system evolves with the connection of new generators and loads in response to the price signals given by the market, the contribution of the other (non competition related) benefits to the overall benefits of interconnection will diminish. This will mean that competition benefits will become an increasingly important source of the benefits of interconnection. Therefore, more time and effort will need to be spent in understanding the nature of these benefits and how they can be measured.

1.2 PURPOSE OF REVIEW

The purpose of this project is to evaluate the increase in economic value, as measured by net change in producer and consumer surpluses, resulting from increasing the capacity of certain transmission interconnects. The results of this analysis will provide one of the inputs into a wider review of the costs and benefits of these transmission augmentations.

More specifically, The Australian Competition and Consumer Commission (ACCC or Commission) has asked Frontier Economics to evaluate the so-called "competition benefits" of SNOVIC 400 – this is a 400 MW augmentation of the existing interconnect between Snowy and Victoria that *has already been built*. This augmentation raised the transfer capacity from the Snowy region to the Victoria region from 1,500 MW to 1,900 MW. This augmentation does not normally increase the transfer capacity from Snowy into NSW however – that is only the southern flow transfer capacity has been improved from this augmentation.

The Commission ultimately seeks to analyse imperfectly competitive behaviour in the NEM as a function of network and market structure in the short-term and the long-term, in order to assess how a transmission augmentation may improve economic efficiency in both the short and long term.

The Commission proposes to use this work to ascertain the appropriateness of its definition of "competition benefits" as well as the practicability of using market modelling to calculate these benefits.

This report contains the following sections:

- Section 2 outlines Frontier's analytical approach;
- Section 3 presents the key modelling assumptions used in this analysis.
- Section 4 describes Frontier's modelling methodology;
- Section 5 presents the results of the modelling and the calculation of competition benefits; and
- Section 6 presents some conclusions resulting from the analysis.

2 Analytical approach

In this section the competition benefits of transmission interconnection in the context of a wholesale electricity market are generally described. This is followed by a brief description of the methods that can be used to measure competition benefits, and their pros and cons. This section concludes with a brief description of the economic modelling approach used by Frontier Economics to measure the competitiveness of oligopolistic electricity markets.

2.1 IDENTIFYING AND MEASURING COMPETITIVE BENEFITS

Traditionally, the competitiveness of markets have been measured and compared using concentration ratios, or estimates of how much prices diverge from costs of production.

These approaches do not perform well in the context of an electricity market where the structure, market rules, hedging contracts, the plant mix of specific players, the elasticity of demand and the threat of regulation have a significant bearing on the degree of competitiveness in the industry.

More recently the literature has highlighted the role that market simulation models can play in examining strategic behaviour of firms in the context of oligopolistic markets. These models can be used to simulate the effects of alternative market structures on market outcomes. This literature has highlighted the importance of simulating the details of a market – its structure, the role of contracts, the plant mix of specific players - as a means of assessing the degree of competitiveness in the industry.

The approach that has emerged as the most preferable, but is still not ideal, is that based on game theory – a technique with a strong theoretical grounding. Game theory is a branch of mathematical analysis which is designed to examine decision making when the actions of one decision maker (player) effects the outcomes of another player, which may then elicit a competitive response that alters the outcome for the first decision maker. Game theory provides a mathematical and, therefore, systematic process for selecting an optimal or best strategy given that a rival has their own strategy and preferred position. This approach does not suffer the drawbacks of other techniques which fail to account for the dynamics of the industry - for example, residual demand analysis.

Game theory is well suited to application in power markets where the 'game' is governed by a well-defined set of rules (bidding and price setting) on a repeated basis. That is, the operation of a power market is a systematic process. Lessons learned in one trading period about the bidding practices of competitors will be drawn upon to formulate bids for subsequent trading periods.

The number of potential combinations of bids under the wide range of power system conditions is vast. It is not possible, nor useful, to attempt to try and guess the 'right' combination of bids from the millions of possible combinations.

But most pool price forecasting involves exactly this. That is, analysts make a guess, based on their experiences and prejudices, of a combination of generator bids to produce the price they generally expected in the first place. This is a poor basis for assessing the economic merit of important electricity infrastructure projects. A more robust, methodical approach is needed. Game theory provides such an approach.

One of the key outputs of a game theoretic model is a Nash Equilibrium. John Nash developed a logical and systematic method for identifying the equilibrium decision point where within a vast array of choices. The equilibrium point identifies the point from which no participant has an incentive to depart from since they will be forced back to this point through the processes of 'competition'. In a power market the Nash Equilibrium identifies the set of bids that, if the participants were rational, would choose under a given set of market conditions. This set of bids would produce a corresponding price. Comparing the generator bids and the calculated prices before and after the development of a new interconnect provides *the basis* for assessing the value of competition benefits arising from increased interconnection.

2.2 DEFINITION OF COMPETITION BENEFITS

2.2.1 Frontier's definition

Frontier's approach to the calculation of competition benefits is as set out in the note for TransGrid that was attached to TransGrid's submission.[1]

To recap, it is worth beginning by noting that the original regulatory test was careful to measure only economic benefits from an augmentation that arose due to cost savings in ***competitive*** dispatch: Note 1(b)(iii) specifies that, under the regulatory test, only the efficient and ***competitive*** costs of supplying electricity are relevant. This approach allows market benefits to be calculated assuming short-run marginal cost (SRMC) bidding, which has the benefits of:

- avoiding the difficulty and controversy of predicting actual bidding and dispatch outcomes in the presence of any degree of market power; and thereby
- enabling any party with the same input data (for example of generator costs) to arrive at similar outcomes.

However, the approach in the original regulatory test does suffer from the drawback of being an unrealistic measure of actual market benefits of an augmentation where bidding is not fully competitive. Frontier's approach to defining competition benefits is therefore geared towards measuring what ***additional*** benefits of an augmentation might accrue to the market if the assumption of competitive bidding were relaxed.

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1 ACCC web site address: http://www.accc.gov.au/content/item.phtml?itemId=261716&nodeId=file402850bdd9937&fn=TransGrid%20submission.pdf

For this reason, Frontier uses the term "competition benefits" to refer to any additional benefits (over and above conventionally-measured net market benefits) that are expected to flow from taking into account likely bidding behaviour, modelled on a consistent and defensible basis. Frontier uses the gaming module of SPARK for this purpose, which in turn is based on a Nash Equilibrium (NE) - style solution concept (described below).

Frontier's definition of competition benefits involves taking expected market benefits *after the augmentation* given likely NE bidding behaviour and subtracting:

- expected market benefits given likely NE bidding behaviour *before the augmentation*; and
- expected *net* market benefits of the augmentation assuming competitive bidding both before and after the augmentation (conventional net market benefits).

Hence, the total net market benefit of an augmentation is the sum of:

- conventional net market benefits (as defined under the original regulatory test); and
- competition benefits.

For example, our modelling found the total benefits of SNOVIC 400 to be $40 million in the 2004/05 year alone. At the same time, if the conventional net market benefits of SNOVIC 400 – as required by the original regulatory test – is $4 million the competition benefits would be $36 million.

2.2.2 ACCC definition

In our view, one of the issues with the ACCC's proposed definition of "competition benefits" is that it does not dovetail neatly with the definition of conventional net market benefits in the original regulatory test.

Appendix D to the ACCC's draft decision divides "total benefits" into:

- "Efficiency benefits" – the difference in total surplus resulting from the augmentation but assuming no change in bidding behaviour; and
- "Competition benefits" – the difference in total surplus resulting solely from a change in bidding behaviour brought about by the augmentation.

The ACCC's definition of "efficiency benefits" differs from the definition of conventional net market benefits. Notably, if the ACCC's measure of competition benefits is added to conventional net market benefits, the aggregate figure is not necessarily the same as "total benefits" defined above.

If the purpose of defining competition benefits is to place a value on the change in the degree to which generators' bids exceed SRMC, the ACCC's definition is probably appropriate. However, if the purpose of defining competition benefits is to determine what increases in surpluses are likely to flow from relaxing the assumption of competitive bidding, we believe that Frontier's definition makes more sense.

We have found that the ACCC's definition of competition benefits can lead to some difficulties. Due to the way non-competitive generator bidding often manifests in the NEM, an augmentation may lead to a *negative* competition benefit. This is because generators in importing regions often react to the increased energy imports enabled by an augmentation by bidding *even more* above SRMC. Hence, the modelling impact of allowing generator bids to change is often to *reduce* total benefits from what they would be otherwise. Frontier's definition of competition benefits ensures that it is less likely to be negative because the focus is on measuring any addition to conventional market benefits rather than on measuring the extent to which generator bidding exceeds SRMC.

2.3 MEASURING COMPETITION BENEFITS USING SPARK

Frontier Economics has developed its own game theoretic model of electricity markets – *SPARK*. *SPARK* determines, *inter alia*, the Nash Equilibrium bidding strategies for all generators under realistic market conditions. *SPARK* is based on a realistic treatment of a power system, including, for example, generator operating characteristics, transmission losses and constraints, demand fluctuations, etc. That is, *SPARK* does what standard electricity market/dispatch models do, but it also determines Nash Equilibrium bidding outcomes.

The model can be operated to find the least *cost* operation of the system (i.e. economic dispatch), or it can be operated to find the most profitable operation of the market (that is the highest equilibrium price) – the latter approach is used in this review. Moreover, our model will systematically account for the effect that contracts have on the bidding behaviour of generators as well as other real life market constraints.

As with any model, the results need to be interpreted carefully. For example, the model will not be concerned about the response of, say, a regulator to extreme price spikes that may result from the 'optimal' set of bids. This normally means that once the modelling results are produced, these may need to undergo a 'reality' test. This could result in a modification of the modelling assumptions (such as moderating the range of bids that generators could choose), or the exclusion of certain, implausible results. For the purposes of this study, which focuses on testing the analytical approach, this screening of modelling results has not been performed. Therefore, while the results are broadly sensible, before they could be reliably used, more screening and sensitivity analysis would need to be conducted.

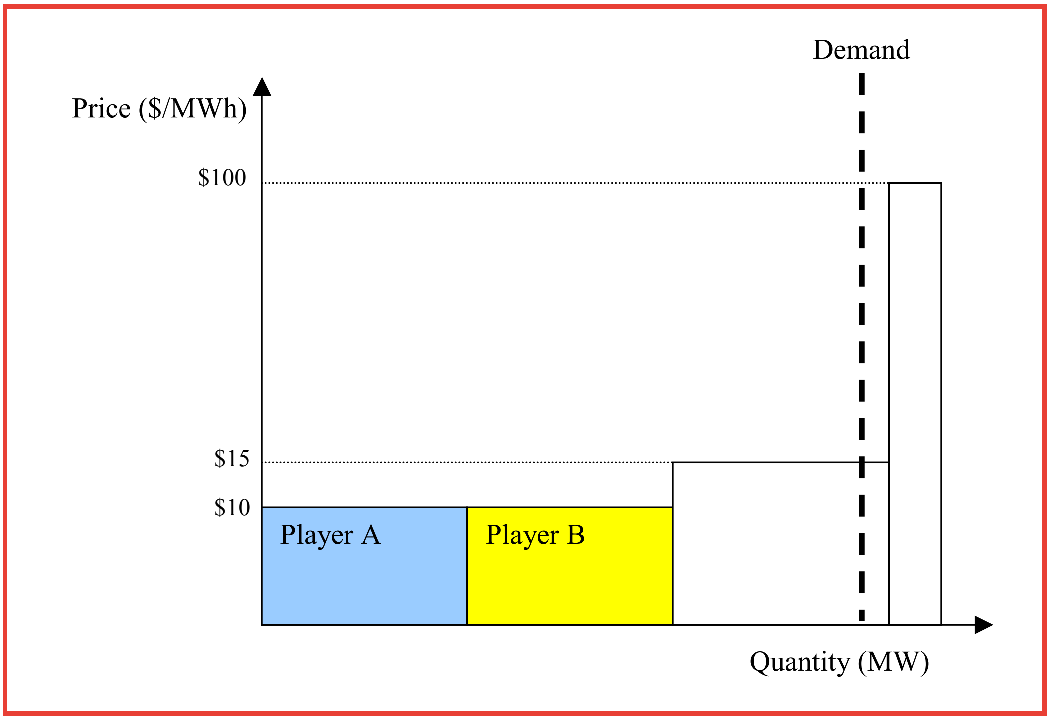
Simplified example of game theory approach

The following examples *illustrate*, in simple terms, the application of game theoretic analysis to the operation of a power market and it's general implementation in *SPARK*.

Consider a single regional market, with 2 players, A and B, of equal size (say 100MW) and costs (say \$10/MWh). There are other higher cost generators in the market as shown in the aggregate supply demand diagram in Figure 1. Demand is at a level above the combined capacities of A and B, and intersects at a slightly higher cost generator at price \$15/MWh.

Under the bids as shown, both A and B make small profits equal to $5/MWh ($15-$10), multiplied by their output of 100MWh giving $500 each.

Figure 1: Example supply/demand diagram



Under these conditions, either player could withdraw a small amount of capacity to push the price up to $100/MWh. Assume A withdraws 10MW and price is just set at $100/MWh, then A's profit becomes 90MW*($100-$10) = $8100. And B's profit becomes 100MW*($100-$10) = $9000. Conversely, B could withdraw 10MW, and the profit results would be reversed. Further if both A and B withdrew 10MW each, the price would be set at $100/MWh and their profits would be 90MW*($100-$10) = $8100 each.

Using these results, we can construct a game payoff matrix as shown in Figure 2.

Figure 2: Payoff matrix, example 1

		Player B	
		Bid 100MW	Bid 90MW
Player A	Bid 100MW	$500 , $500	$9000 , $8100
	Bid 90MW	$8100 , $9000	$8100 , $8100

Note: Payoffs are in Player A, Player B order.

Now consider Player A's incentives. If A thought B would bid 100MW, A would do 'best' by bidding 90MW for a profit of $8,100 (compared to $500 by bidding 100MW). If A though B would be 90MW, A does best by bidding 100MW for a profit of $9,000 (compared to $8,100 by bidding 90MW). As the game is symmetric, B would choose likewise. In this example, we have two equilibria, (90MW, 100MW) and (100MW, 90MW). At either equilibrium point, no player can increase their profit by unilaterally changing their bid.

SPARK can handle many players, with many possible bids in a multi-regional market with transmission constraints, and although the stylised example is quite simple in comparison, the game theoretic concepts implemented in *SPARK* are similar to those applied to this simplified example.

2.4 STATIC VS DYNAMIC COMPETITION BENEFITS

The development of an interconnect will change both the way the existing stock of plant will be used and could also change the pattern of investment compared to the situation if the interconnect was not developed:

- **Changes to the dispatch and pricing of existing plant (static benefits):** Increased competitive pressure from a new or enhanced interconnector is likely to dampen generators' ability to raise prices above costs in the importing region (if the market is not already perfectly competitive). At the same time the same interconnector may enhance the ability of generators in the exporting region to raise prices. Either way, the interconnector could alter bidding behaviour which could alter the dispatch of plant. Whether or not the overall market is better off, in terms of lower cost dispatch and lower prices, which supports greater economic activity, is an empirical question, and is the subject of this study. For the purposes of this study we have termed this form of 'competition benefit' as being the ***static benefits***. This is because these benefits are concerned with making more efficient use of *existing* inputs. The fact that these benefits are called 'static' does not necessarily infer that they are enjoyed only in the short term. Indeed, the pro-competitive bidding and dispatch effects of a new or enhanced interconnector would be expected to continue into the longer term.
- **Changes in investment patterns (dynamic benefits):** To the extent that an interconnector makes the generation market more competitive, this may have an effect on the timing, size and location of investment in new generators. For example, an incumbent generator with a degree of market power may decide to invest in new capacity *earlier* than an independent investor, in order to entrench its market position. The incumbent may choose to make a short-term loss on the new capacity by building new capacity early in order to avoid a larger loss that may result from a new competitor building the plant and eroding incumbent market power. This pre-emptive investment represents a waste of the community's resources. With a new or enhanced interconnector the generator may no longer be able to profitably engage in this type of behaviour. This may cause generators to build generators closer to the most optimal pattern in terms of when, where and how much capacity, and of what type. This represents a saving of resources in the longer term.

Whilst the static and dynamic competition benefit impacts are inherently inter-dependent, an initial static analysis can be used to assess the likely magnitude of potential competition benefits. If these benefits are significant, the dynamic analysis, being much more conceptually difficult and computationally demanding, should be undertaken. If, however, the benefits from the static analysis are not significant, this may suggest that the benefits arising from dynamic analysis are also likely to be small and hence the value of undertaking a dynamic analysis may be limited. This is because the impacts of competition on investment are only likely to be significant if the first-round impact on prices is significant.

This study is only concerned with developing and applying a framework for measuring the *static* competition benefits of interconnects.

3 Modelling assumptions

This section discusses the modelling assumptions used in the calculation of competition benefits.

3.1 NETWORK REPRESENTATION

This analysis uses a five region representation of the NEM: Queensland, New South Wales, Snowy, Victoria and South Australia.

3.2 GENERATION ASSUMPTIONS

The assumptions regarding generator:

- capacity (nominal and summer);
- variable costs;
- minimum stable generation levels
- outages;
- ramp rates;
- energy constraints (in the case of hydro units); and,
- pump characteristics (in the case of hydro pump units),

are presented in detail in Appendix A. These assumptions are largely based on data from the NEMMCO *Statement of Opportunities 2003* (SOO), and the ACIL report to the IRPC and NEMMCO, *SRMC and LRMC of Generators in the NEM,* in April 2003.

3.3 TRANSMISSION ASSUMPTIONS

The assumptions regarding transmission:

- transfer capabilities; and
- losses,

are presented in Appendix A. Interconnectors are assumed to be capable of transferring their nominal capacity at all times. The nominal capacity assumptions come from the SOO. In practice, interconnects transfer capability may change from one dispatch interval to the next depending on system conditions, and may, at times, be much lower than the nominal capacity.

3.4 STRATEGIES AND PLAYERS

Game theory analysis in a market such as the NEM, with multiple pricing zones, transmission constraints and a significant number of players is computationally demanding. Comprehensive analysis quickly becomes intractable as each player has effectively an infinite number of possible bids to be assessed against all possible combinations of bids from the other players.

The number of combinations of bids to be evaluated increases exponentially with the number of strategic players, as well as the number of available bidding strategies available to each strategic player. Simplifying assumptions are made to ensure the computational requirements of the analysis remain manageable:

- The types and ranges of strategies can be limited. In *SPARK*, bidding strategies can involve bidding the available capacity at different prices, or making more or less capacity available to the market, or a combination of both. Within these choices, the price range over which generators are allowed to bid, and the increments within this range, can be limited. Similarly, the extent of capacity withdrawal choices can be contained to a level that is plausible, and again the number of discrete choices within this range can be restricted to make the computational problem more tractable.
- The number of strategic players can be limited. Players can be categorised as either 'strategic' or 'non-strategic':
  - *Non-strategic* players are given fixed bids (ie. their bids remain constant no matter how other players bid – fixed bids can be in any form or level, just as so long as they are fixed); and
  - *Strategic* players are given a set of potential bids to choose from and will respond to changes in other players' bids in order to maximise their payoff by choosing the most profitable bid from those available.
- The set of potential bids available to strategic players can be limited to decrease the number of bidding combinations to be evaluated.

The strategic participants and their strategic power stations used in this analysis are shown in Table 1. To limit the number of strategic participants only the largest generation portfolios in each region and across the NEM have been assumed to behave strategically.

In terms of the Strategic participants are assumed to bid a proportion of the total combined capacity of their power stations into the market. For instance a strategy of 75% shown in the table corresponds to a participant withholding 25% of the combined capacity of their strategic power stations. It is assumed that participants, except TXU, are contracted to a level whereby they would be unwilling to remove more than 25 % of their capacity. TXU holds a number of peaking stations in its portfolio of assets and is allowed to remove slightly more, up to 40%, of its capacity compared to other strategic participants.

Table 1: Strategic participants

Strategic participant	Strategic stations	Strategies
CS Energy	Callide B, Callide C1, Swanbank B, Swanbank E	95%, 85%, 75%
Delta	Mt. Piper, Munmorah, Vales Pt, Wallerawang C	95%, 85%, 75%
International Power	Dry Creek, Hazelwood, Mintaro, Port Lincoln, Snuggery, Pelican Pt	95%, 85%, 75%
Loy Yang A	Loy Yang A	95%, 85%, 75%
Macquarie Generation	Liddell, Bayswater	95%, 85%, 75%
QPTC (Enertrade)	Gladstone, Collinsville	95%, 85%, 75%
Tarong	Tarong, Tarong North	95%, 85%
TXU	Torrens Island A, Torrens Island B, Newport, Jeeralang A, Jeeralang B	90%, 60%

3.5 CONTRACT POSITION OF STRATEGIC PARTICIPANTS

All strategic participants are assumed to hold contracts at 70% of the output they would produce under marginal cost bidding. The contract quantity is assumed to vary accordingly with expected output at each demand point. Swap contracts are assumed. However SPARK is capable of modelling, more or less, any contract or portfolio of contracts.

3.6 MODELLING PERIOD

For the purposes of this exercise the competition benefits are estimated for the financial year 2004/05.

3.6.1 Demand points

The electricity demand for 2004/05 is based on the Medium growth 50% POE forecasts from the SOO and is characterised using 60 representative demand points. Figure 3 shows the 60 points used in the modelling. The hours of very high demand during the year (i.e. when generators are most likely to be able to raise the pool price above costs) are modelled with relatively more demand points than demand at average and low demand levels (i.e. when generators are least likely to be able to raise the pool price above costs).

Each demand point is weighted by its expected frequency of occurrence during the year so that yearly average results can be found by adding up outcomes for each demand point after weighting each by its relative expected frequency.

Subsequently the points of low and average demand, which occur frequently throughout the year, receive a higher weighting than the peak demand points, which occur infrequently. Figure 4 shows the relative expected frequency of occurrence of each demand point.

The points are grouped as follows in Table 2.

Table 2: Demand point description

Season	Demand points	Hours	Description
Winter	0-4	10	NSW peak
	5-9	10	VIC peak
	10-14	10	QLD peak
	15-19	10	SA peak
	20-29	5,792	Remaining hours
Summer	30-34	10	NSW peak
	35-39	10	VIC peak
	40-44	10	QLD peak
	45-49	10	SA peak
	50-59	2,888	Remaining hours

Note that the seasons have been defined to capture the impacts of summer capacity de-rating for certain generators. We assume that the de-rating would only apply during the relatively hot months, i.e. December-March. Hence, Summer has been defined as December-March, and Winter as April-November.

Figure 3: Electricity demand (60 points)

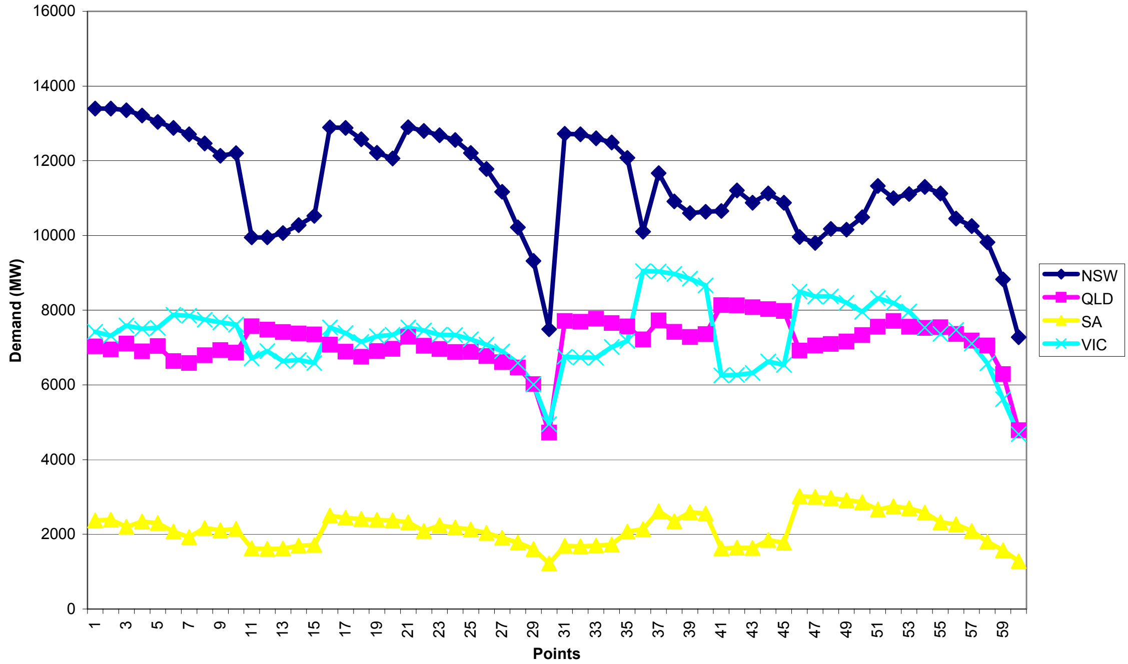
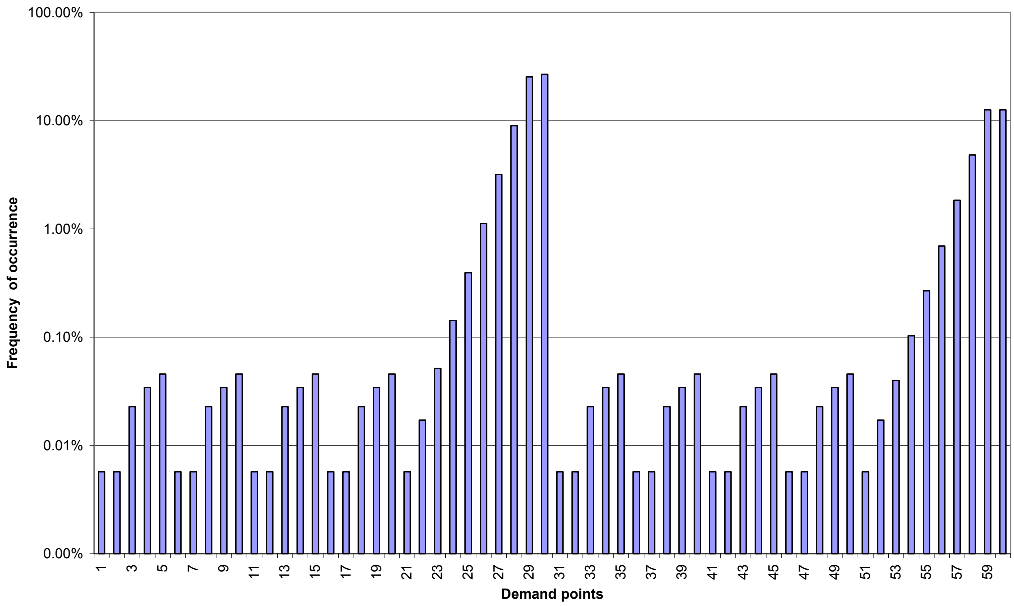


Figure 4: Probability of occurrence of each demand point



3.6.2 Demand elasticities

The regional demand elasticities used in the analysis are shown in Table 3. The results are also presented assuming perfectly inelastic demand.

Table 3: Regional demand elasticities

Region	Demand elasticity
NSW	-0.37
QLD	-0.29
SA	-0.32
VIC	-0.38

Source: NEMMCO Statement of Opportunities 2003.

3.6.3 Demand side participation

Levels of demand side participation in each region are presented in Appendix A

3.7 EQUILIBRIA SELECTION

It is possible that more than a single equilibrium can be found for each demand point using SPARK. In these cases both:

- the average outcome (where each equilibrium is equally likely to occur); and,
- the range of outcomes (using the 10th, 50th, and 90th percentile outcomes),

are calculated.

4 Methodology

4.1 STRUCTURE AND OPERATION OF SPARK

SPARK considers each demand point individually when running a game, i.e. a game is considered to be at a particular (representative) demand point. In analysing multiple demand points, a number of games, one for each point, are run.

The user defines which generating portfolios (players) are strategic and what strategies they have available. *Strategies* can be either capacity withdrawal strategies and/or pricing strategies. Non-strategic players will generally bid 100% of capacity at marginal cost, or bid according to a predefined rule, e.g. according to a set bid profile (in price and quantity bands), or target a percentage of demand (bid to achieve a market share strategy).

At each demand point *SPARK* will perform a dispatch for every possible combination of strategies and evaluate, for each combination, the market outcome (regional prices, dispatch quantities, interconnector flows) and portfolio payoffs. Portfolio payoff is calculated as pool revenue (output multiplied by pool price) less short-run operating costs (marginal cost multiplied by output) less/plus any contract difference payments. In the case where everyone acts competitively, bidding 100% of capacity at marginal cost, there is only one bidding combination, and hence, one dispatch operation. Where there are 2 strategic players each with 3 possible bids to choose from there are 9 possible outcomes (3 x 3) and nine separate dispatch operations considering each combination of bids in turn. In general the product of the number of bids available to each portfolio gives the total number of bidding combinations to be evaluated.

SPARK will then consider the best response (maximum operating profit) of each strategic player against all possible combinations of strategies by other players. In effect *SPARK* chooses the best strategy for a portfolio, the strategy that maximises their payoff, in every possible scenario that can occur given the range of bidding choices provided. An equilibrium outcome is found when the best response of all players coincide, a Nash Equilibrium.

It is possible, an indeed usual, for more than a single Nash Equilibrium is found for each game, in this case all equilibrium results are produced. The range of equilibrium can sometimes be large, which reduces the usefulness of this technique. While there are techniques available for focussing on a selection of equilibrium outcomes, for the purposes of this study the robustness of the conclusions are tested by examining the variation in results caused by range of equilibrium outcomes (see Section 5.6).

SPARK produces the following outputs for each equilibrium point within each game:

- Regional prices;
- Dispatch quantity for each generating unit;
- Interconnect flows and losses;
- Equilibrium bidding strategies for each player; and
- Portfolio payoffs.

In games with multiple equilibria, summary statistics are available for each of the outputs (minimum, average, mode, maximum and standard deviation).

In analyses performed over a range of demand points, the outputs can be aggregated/averaged based on the expected frequency of occurrence of that particular (representative) demand point over a year. For example, an analysis run over two demand points, say one peak and one off-peak, produces an equilibrium price for each point, say $30/MWh and $20/MWh respectively. If the expected frequency of occurrence for the peak point is 45%, and 55% for the off-peak point, then the weighted average price over the year would be $24.50/MWh (0.45*30 + 0.55*20).

4.2 APPLICATION OF SPARK

The modelling approach employed in this study focuses on measuring the competition benefits arising from changes in bidding behaviour due to the competitive impact of transmission investment options. The methodology employed in this analysis is described in more detail below.

This first stage analysis will be evaluated over a one-year modelling horizon in the absence of any dynamic investment effects.

The calculation of competition benefits arising from an augmentation to an interconnector requires the analysis of the behaviour of market participants with and without such an augmentation.

The modelling methodology involved a three-stage approach:

- the first stage determined the likely pattern of dispatch for energy constrained hydro units and the level of contract cover of the strategic participants across the year for each of the three scenarios using Frontier Economics' electricity market model *WHIRLYGIG*;
- the second stage analysed the likely market outcomes, having regard to the presence of any generator (perhaps transient) market power, under each scenario using Frontier Economics' electricity market model SPARK; and
- the result of the second stage are used to calculate the cost and competition benefits from the transmission augmentations.

These stages are described in more detail in the subsections below.

4.3 FIRST STAGE – DETERMINING HYDRO DISPATCH AND CONTRACT LEVELS

The first stage uses Frontier Economics' medium to long-term dispatch/investment model, *WHIRLYGIG*. *WHIRLYGIG* models the efficient operation of generators to meet demand over a medium to long-term modelling horizon (in this case 1 year) – that is, economic dispatch. The market equivalent of economic dispatch is where all generators bid their marginal costs of production.

More specifically, *WHIRLYGIG* is a mathematical optimisation model where the objective function in this case is to minimise the total cost of meeting system demand. If this is run in the short term, where no new capacity is required, it will minimise operating costs. But if the model is run for the longer term where new capacity would be needed to meet certain reliability criteria, the model will minimise both capital and operating costs.

The optimisation includes constraints on hydro usage and utilises these limited resources optimally to meet demand. The key output of this stage of the modelling is the pattern of dispatch. Both:

- the optimal pattern of hydro generation across the year; and,
- the level of contracts held by strategic participants,

are calculated from the dispatch results and used as inputs to the second stage.

4.3.1 Hydro dispatch

Modelling the operation of hydro generators requires an assumption about how scarce water is used over time. The assumption used in this analysis is that hydro generators are dispatched to minimise the cost of meeting demand. In *WHIRLYGIG*, this is analogous to dispatching hydro generation at times when the output, and hence water, is the most valuable in terms of the price its production receives in the market. Thus, this is a fairly good characterisation of how an energy constrained hydro plant would operate in the context of a market as well.

The *WHIRLYGIG* optimisation will ensure that hydro units will operate at times during the year when the value of water is maximised subject to meeting other transmission constraints and other constraints on their operation.

Hydro generators' bidding incentives reflect inter-temporal objectives to maximise the value they receive for their water across the whole year. The computational requirements to include these explicitly in the strategic analysis in the second stage would make the analysis intractable. Hydro units are therefore assumed to be non-strategic in the following game theoretic analysis and follow the optimal pattern of dispatch found in this first stage in order to ensure the analysis remains tractable. This would tend to cause the competition benefits to be underestimated to the extent that any competitive impact of an augmentation on hydro bidding is not captured in the analysis.

4.3.2 Contract levels

Under some circumstances financial firm hedging contracts can have the (probably short term) effect of dampening generators' incentive to bid high prices. In general, risk adverse generators will *tend* to bid a quantity of capacity at its marginal cost equivalent to the quantity of firm contracts held by the generator. This type of bidding behaviour tends to make the market more competitive in the short term. Given the analysis is being conducted over a year, it is important to consider the impact of contracts on bidding behaviour and, hence, the competition benefits of the transmission augmentation.

In the longer term, rational generators would not contract away the value of any market power they have. Thus, they would learn to adjust their contract levels and prices to maximise their profits, given their market power.

For the purpose of this analysis it has been assumed that the level of contracts for strategic participants in the second stage is assumed to be 70% of their output found at each demand point in the first stage. In the second stage strategic analysis, this leaves 30% of the output they would expect to generate under marginal cost bidding potentially exposed to the spot price. Setting contract levels in this way sculpts the level of contracting to the pattern of output of each generator, so that participants have a greater amount of their output contracted at times of peak demand and a lower amount at off-peak times.

4.4 SECOND STAGE - CALCULATING COMPETITION BENEFITS

The second stage of analysis involves using *SPARK* to determine equilibrium bidding patterns and, hence, prices before and after the interconnect. The set of modelling assumptions used in this stage of the modelling are presented in Section 3.

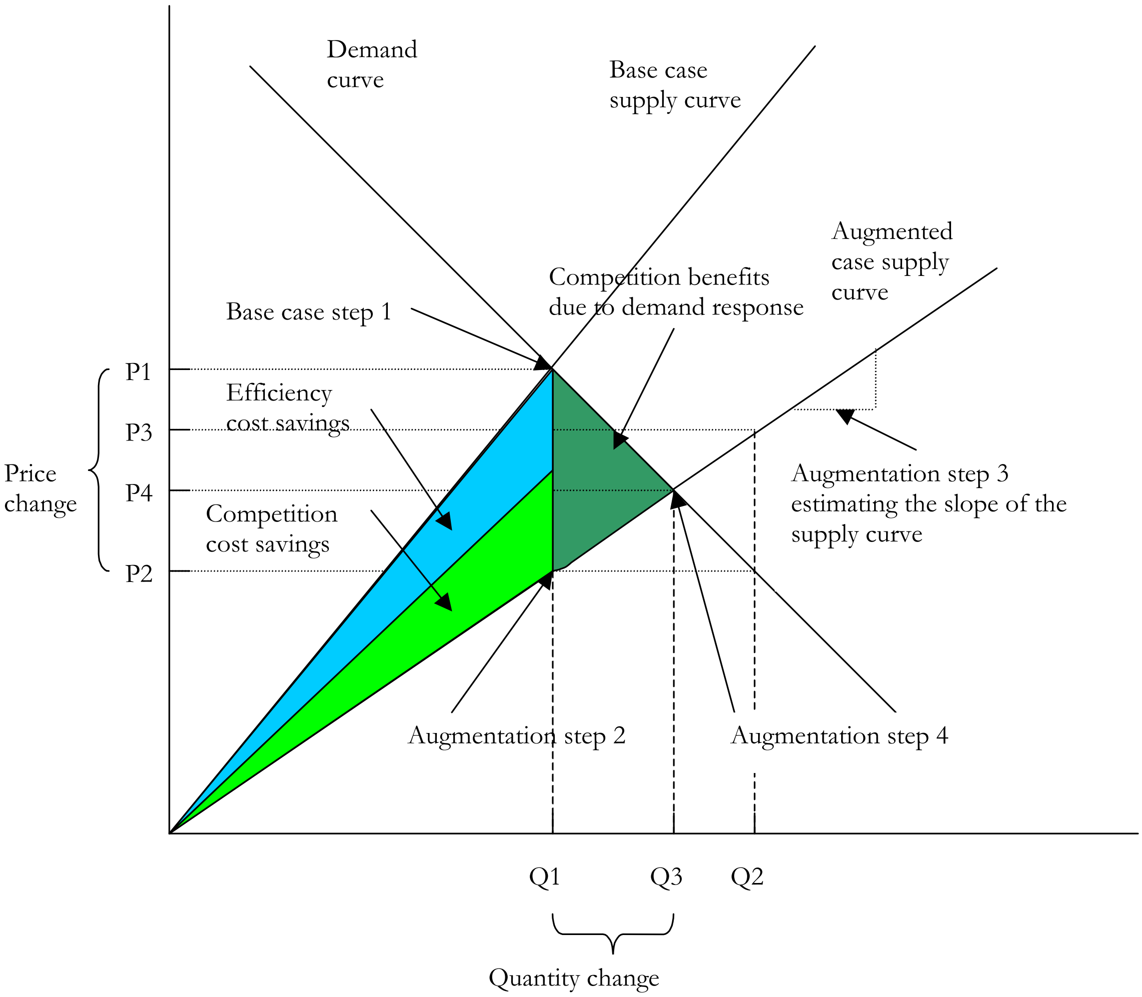
The methodology for calculating the competition benefits for both augmentations consists of five steps:

- Step 1 - calculating the demand weighted average price outcome for 2004/05 and the cost of meeting demand under the base case;
- Step 2 - calculating the demand weighted average price outcome for 2004/05 after the augmentation without including a demand response;
- Step 3 - calculating the demand weighted average price outcome for 2004/05 including a demand response in order to estimate the slope of the supply curve;
- Step 4 – calculating the equilibrium price and quantity of demand that balances supply and demand after the augmentation, and the resulting production costs; and,
- Step 5 – calculating the total surplus in both the base case (Step 1) and the post-augmentation equilibrium case (Step 4) to determine net benefits.

The first 4 steps are illustrated in Figure 5. The total benefits calculated in step 5 is the total of three regions in the figure:

- cost saving benefits resulting from a more efficient dispatch, i.e. less constrained (light blue shaded region);
- cost saving benefits resulting from an increase in the level of competition, i.e. more competitive bidding behaviour (light green shaded region); and,
- benefits arising from an increase in the level of aggregate supply and demand (dark green shaded region).

Figure 5: Calculation of competition benefits



Note that demand weighted average annual prices are used as opposed to time-weighted prices. Demand weighted prices reflect the average price paid per MWh for electricity by consumers, and is an appropriate measure of price for use with an elasticity of demand to determine demand changes.

The demand-weighted price for a year is calculated by weighting the average equilibrium prices at each demand point by the level of demand and expected frequency of occurrence of that point over the year.

Equation **1** shows the calculation of the demand-weighted price. For each demand point *i* the average equilibrium price is weighted by the demand at that point (demand divided by total annual energy) and its frequency of occurrence (hours divided by 8760).

Equation 1: Demand weighted price

$$\text{Demand weighted price} = \sum_i \left(\text{Average Equilibrium Price}_\text{i} \times \frac{\text{Demand}_\text{i}}{\text{Total Annual Energy}} \times \frac{Hours_i}{8760} \right)$$

4.4.1 Base case – step 1

The first step finds the demand weighted average price for 2004/05 (price *P1* in Figure 5) in the base case. SPARK analyses the 60 representative demand points for 2004/05 and for each point finds the equilibrium market outcomes such that each strategic participant is unilaterally maximising their total operating profit (pool revenue minus operating costs and difference payments on contracts). In cases where there are multiple potential market equilibria, each equilibrium is treated as equally likely and the average equilibrium prices and costs are calculated for that point. The demand-weighted price for the year *P1* is calculated using Equation 1.

The cost of meeting demand is the area under the supply curves shown in Figure 5. It is calculated by finding the total operating costs of each generator *g* across the year plus any deficit MWh priced at VoLL ($10,000/MWh). The total cost of meeting demand is shown in Equation 2. Note that contract difference payments are ignored in this calculation as a cost, as these represent transfers between producers and consumers.

Equation 2: Total cost of meeting demand

$$\text{Total cost of meeting demand} = \sum_\text{g} \left(\text{Total output}_\text{g} \times \text{marginal cost}_\text{g} \right) + \sum \left(\text{Deficit MWh} \times 10{,}000 \right)$$

4.4.2 Augmentation step 2

Step 2 calculates the price change that occurs due to the augmentation (price *P2* in Figure 5). This step includes the relevant interconnect augmentation and repeats the *SPARK* analysis from step 1 to calculate the demand weighted average price for 2004/05 and the total and average cost of meeting demand.

This step models the market outcomes that would occur if the relevant augmentation proceeded and demand remained unchanged from the base case.

The regional price changes from the augmentation are calculated as *P2–P1*. However these price changes ignore any demand response from consumers. In Figure 5 the equilibrium prices and quantities after the augmentation are in fact *P4* and *Q3*. The regional demand and supply responses are found by estimating the slope of the regional demand and augmented supply curves. The slopes of the regional demand curves are estimated using the demand elasticities given in Table 3. The slopes of the augmented supply curves are estimated in step 3.

4.4.3 Augmentation step 3

The purpose of Step 3 is to estimate the slope of the augmented supply curves in each region by finding the average price *P3* on the augmented supply curve that results from an increase in demand from *Q1* towards *Q2*. It is assumed that the supply curve about the point of interest is linear.

The supply curves in each region are inherently inter-dependent because of the interconnected nature of the NEM. For example, the supply curve in Victoria is a function of the generator supply curves in all regions as power can be transported via interconnects into Victoria from other regions. For this reason, estimation of the slope of the regional supply curves is difficult, and needs to be undertaken with due consideration of the interdependent nature of the regional supply curves.

Our approach to undertaking this estimation is to measure the slope of each regional supply curve with respect to a small change in demand in each region. That is, we measure the change in the NSW, QLD, SA and VIC expected average annual equilibrium price with respect to a small change in NSW demand. Then we repeat for a small change in QLD demand, and so on.

The resulting prices from this analysis allow the construction of an inverse cross-elasticity of supply matrix giving the relationships between relative demand changes in each region to relative price changes in each region.

The inverse cross-elasticity of supply matrix, in conjunction with an inverse elasticity of demand matrix and the regional price/quantity results from step 1 and step 2 can be used to determine the post-augmentation equilibrium point for each region. This calculation is performed in step 4.

4.4.4 Augmentation step 4

The previous steps provide us with enough information to approximate both the demand and supply curves about the new market equilibrium point using a linear approximation.

The base case price and demand, point (*Q1,P1*) together with an estimation of the slope of the demand curve at that point, using the elasticity of demand, characterise the demand curve around the point of interest.

The regional demand curves are characterised by constructing a cross-elasticity of demand matrix. The matrix, *D*, in this case will be of dimension 4 x 4 (4 regions, ignoring Snowy which has no demand) and is constructed as follows:

- The diagonal elements of the matrix are given by the inverse of the regional demand elasticities; and
- All other elements are zero.

For the assumed demand elasticities given in Table 3, the inverse cross-elasticity of demand matrix is shown in Table 4 below.

Table 4: Inverse cross-elasticity of demand, matrix *D*

	NSW	QLD	SA	VIC
NSW	-2.70	0	0	0
QLD	0	-3.45	0	0
SA	0	0	-3.13	0
VIC	0	0	0	-2.63

The step 2 regional quantity/price points and an estimate of the slope of the supply curve in each region using an inverse cross-elasticity of supply matrix (calculated from the results of step 3) allow a linear approximation of the supply curve about the point of interest to be derived. The matrix, *S*, will be of dimension 4 x 4 (4 regions, ignoring Snowy) and is constructed as follows:

Using (row,column) matrix notation:

$$element(r,c) = \frac{\left(\dfrac{P_{3,r,c} - P_{2,r}}{P_{1,r}}\right)}{\Delta Q_{3,c}}$$

where:

- *element(r,c)* is the matrix element in row/region *r*, column/region *c*;
- $P_{1,r}$ is the demand weighted price for region *r* from step 1;
- $P_{2,r}$ is the demand weighted price for region *r* from step 2;
- $P_{3,r,c}$ is the demand weighted price for region *r* from step 3 for a small change in demand in region *c*;
- $\Delta Q_{3,c}$ is the relative demand change from step 3 for region *c*.

The post-augmentation equilibrium point can be estimated by calculating the intersection points of linear approximations of the regional supply and demand curves as follows:

The demand curve can be represented in matrix notation as:

$$p_d = Dq_d$$

where, p_d and q_d are 4x1 matrices of relative price and quantity changes respectively from the known point ((*Q1,P1*) in Figure 5), and D is the inverse cross-elasticity of demand matrix shown in Table 4.

The supply curve can be represented in matrix notation as:

$$p_s = Sq_s + p_2$$

where, p_s and q_s are 4x1 matrices of relative price and quantity changes respectively from the step 1 point ((*Q1,P1*) in Figure 5), p_2 is a 4x1 matrix representing the change from point (*Q1,P1*) of the known price point on the augmented supply curve, (*Q1,P2*), relative to point (*Q1,P1*), and S is the inverse cross-elasticity of supply matrix defined above.

The intersection point occurs when $q_d = q_s$ and $p_d = p_s$. By setting $p_d = p_s$ and $q_d = q_s = q$:

$$Dq = Sq + p_2$$

Re-arranging and solving for q, gives:

$$q = (D\text{-}S)^{-1}.p_2$$

From this solution for q, p can be calculated by substituting q back into the demand equation:

$$p = Dq$$

The matrices p and q give the price and quantity changes of the post-augmentation equilibrium for each region relative to the pre-augmentation equilibrium.

In order to calculate total surplus in step 5, we also require an estimation of total producer costs at the equilibrium point. Total producer costs can be determined from an estimate of average incremental production costs in each region as follows:

Construct a 1 x 4 matrix, C, which gives the relative incremental total production cost for a given relative change in regional demand. The matrix elements are calculated as:

$$element(1,c) = \frac{PC_{3,c} - PC_2}{\Delta Q_{3,c}}$$

where:

- *element(1,c)* is the matrix element for column/region *c*;
- $PC_{3,c}$ is the total production cost in step 3 for a small change in region *c* demand;
- PC_2 is the total production cost from step 2; and
- $\Delta Q_{3,c}$ is the relative demand change from step 3 for region *c*.

The relative increase in production costs from step 2 to the post-augmentation equilibrium can be then calculated as *Cq* (this gives the percentage increase in production costs over the step 2 costs).

4.4.5 Augmentation Step 5

Gross benefits are given by the increase in total surplus under the post-augmentation equilibrium compared to the pre-augmentation equilibrium.

Total surplus is calculated with reference to Figure 6 below. The figure is a slight modification of Figure 5, where the demand curve is vertical from the base case equilibrium point (*Q1,P1*), up to an assumed willingness to pay of consumers at price *P5*. As we are only interested in the change in total surplus, rather than the absolute value of surplus under any one scenario, the assumed shape of the demand curve above the point (*Q1,P1*) is not important and has been set to provide for ease of calculation.

For the base case, total surplus is given by the area A. In practice, calculation of A directly is not straightforward, however, it is made simpler by:

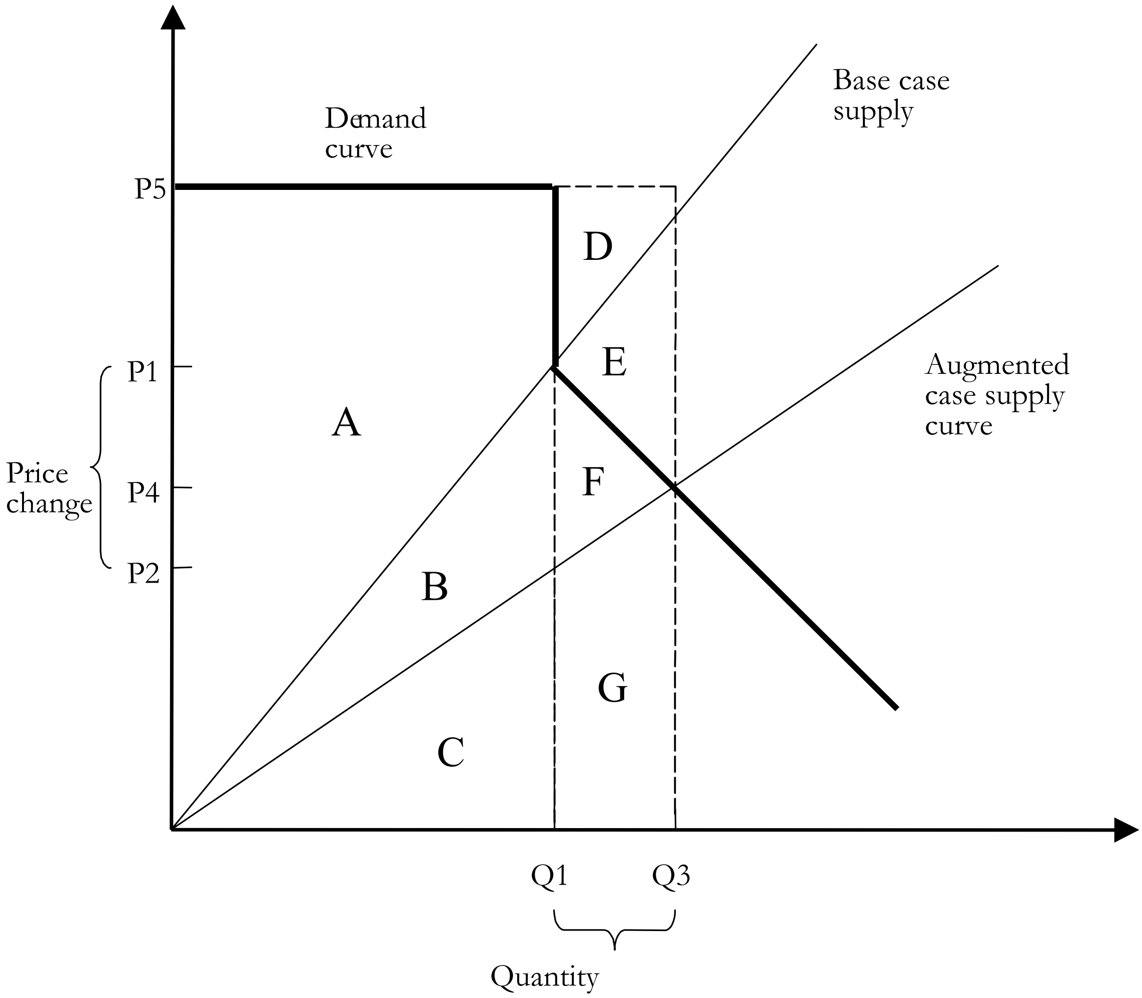
- First calculating the total willingness to pay of consumers, given by the area *A+B+C*. This is simply the assumed willingness to pay, *P5*, times the quantity, *Q1*.
- Second, calculate production costs, given by the area *B+C*. Production cost is an output of the market modelling.
- Finally, the surplus, or area *A*, is given by subtracting production cost from willingness to pay, or *(A+B+C)-(B+C) = A*.

For the augmentation equilibrium point, the calculation is similar, but with one additional calculation:

- First calculate willingness to pay, or the area *A+B+C+D+E+F+G*. As for the base case this is given by willingness to pay, P5, times the quantity, in this case *Q3*.
- Second, the area's *D+E* should not be included in the willingness to pay. This area is calculated as *(Q3-Q1)*(P5-(P1+P4)/2)*. Subtract this from the result of the first step, and we are left with *A+B+C+F+G*.
- Third, production cost is calculated as in step 5, giving the area *C+G*.
- Finally, surplus is now given by subtracting production cost, *C+G*, from willingness to pay, *A+B+C+F+G*, giving *A+B+C*.

The change in surplus can then be calculated as the difference between the base case surplus and the augmentation surplus.

Figure 6: Calculation of surplus



Cost savings are shown as the area *B*. This cost saving includes a component that is due to the productive efficiency impact of the augmentation (which would be realised in a fully competitive market), as well as a component that is due to the productive efficiency impact of increased competition.

We have not attempted to separate these two components out in this analysis, nor separate the area *F* from *B*.

5 Results

The results of the calculation of competition benefits from the 400 MW increase southbound on SNOVIC is presented in this section.

5.1 BASE CASE

The time weighted average prices in the base case vary between \$26.92/MWh in NSW and \$47.56/MWh in South Australia. The demand weighted average prices are higher than these and vary between \$30.45/MWh and \$64.43/MWh in NSW and South Australia respectively.

It should be noted that these prices represent the weighted (according to the frequency of expected demand points) pool price for all identified equilibria This implicitly assumes that all equilibria outcomes are equal likely. In practice, not all equilibria are equally likely. For example, as mentioned above, in calculating the equilibria the model does not consider a range of 'real life' factors, such as generators being concerned about possible retaliatory response by regulators to the pool price being at \$10,000/MWh for extended or frequent periods. For the purposes of this study we have not screened out extreme and, therefore, unlikely equilibria to account for these 'real life' considerations.

In other cases the model may be showing that estimated pool prices are, on average, lower than the actual prices. The differences could be explained by a range of factors. For example, generators may, in practice, favour high priced equilibria outcomes. Alternatively, or at the same time, modelling assumptions may be overly restrictive compared to what is actually the case in the market. For example, in the current modelling exercise, an assumption has been made that contracting levels are standard across all generators in all States. In practice, contracting levels vary considerably across different generators and over time, and this will affect modelling outcomes.

In a 'full blown' assessment of the competition benefits using the approach developed in this study, it would be appropriate to test the sensitivity of the conclusions to the key assumptions. The purpose of this paper is to develop and document a workable approach to measuring competition benefits – it is not intended that an exhaustive analysis be undertaken of the precise value of the competition benefits. For the purposes of this study, if the price estimates are broadly consistent with expected relativities, and costs and prices move in the 'right' way, this is sufficient to test the veracity of the proposed approach.

Table 5: SNOVIC base case results, prices

Region	Time weighted price ($/MWh)	Demand weighted price ($/MWh)	Demand elasticity
NSW	26.97	30.53	-0.37
QLD	26.92	30.45	-0.29
SA	47.56	64.43	-0.32
VIC	42.38	54.07	-0.38

Table 6 below shows the hours of constraint for SNOVIC in each direction under the base case. Note that SNOVIC constrains about 46 hours. This would indicate that the competition benefits are likely to be material for this augmentation. It is important to note that these constraints are determined by the model and do not necessarily reflect the actual level of constraints observed in the market. In a full-blown modelling exercise we would normally adjust the modelling assumptions to reflect something more like the actual performance of the market as a base case.

Table 6: SNOVIC base case constraints

Interconnect	Hours constrained South	Hours constrained North
V_SN	45.6	0

5.2 AUGMENTATION STEP 2

Table 7 presents:

- the demand weighted average price;
- the regional demand;
- the total production cost; and,
- the percentage change in this price from the base case,

in each region.

The 400 MW augmentation of SNOVIC produces significant changes in the demand weighted prices in each region.

Table 7: SNOVIC Augmentation step 2 results

Region	Demand weighted price ($/MWh)	Demand (GWh)	Production cost ($m)	Price change from the base case
NSW	40.31	76,845		32.0%
QLD	40.28	50,114		32.3%
SA	57.37	13,338		-9.6%
VIC	47.52	49,799		-12.1%
TOTAL		190,095	1,968	

5.3 AUGMENTATION STEP 3

Table 8 presents the demand-weighted regional price results for small changes in regional demand from the step 2 case. These are used to estimate the slope of the regional supply curves. The demand changes in each region were chosen as 1% in the opposite direction of the price changes in Table 7 above, except for SA where a 5% change was used due to the relatively lower levels of absolute demand in SA.

Table 8: SNOVIC step 3 prices

Region	Region, demand change%			
	NSW -1%	QLD -1%	SA +5%	VIC +1%
NSW	32.49	33.83	41.00	41.66
QLD	32.79	33.97	41.30	41.66
SA	52.85	52.26	63.88	58.37
VIC	42.44	42.16	51.36	50.66

5.4 AUGMENTATION STEP 4

Table 9 presents the calculated inverse cross-elasticity of supply between each of the NEM regions, referred to as the matrix S.

In addition to S, the matrix D is shown in Table 4, and the matrix p_2 is the Price change column in Table 7.

Substituting these matrices into the solution equations given in Section 4.4.4 yields the resulting post-augmentation equilibrium demand and price points, shown in Table 10.

Table 9: SNOVIC step 3 inverse cross-elasticity of supply, matrix *S*

Region	Region, demand change%			
	NSW -1%	QLD –1%	SA +5%	VIC +1%
NSW	25.86	21.44	0.45	4.43
QLD	24.83	20.93	0.67	4.52
SA	7.09	8.01	2.02	1.55
VIC	9.49	10.01	1.42	5.80

Table 10: SNOVIC post-augmentation equilibrium

	Quantity change	Price change	Quantity	Price
NSW	- 0.66%	1.79%	76,335	$31.08
QLD	- 1.33%	4.59%	49,447	$31.85
SA	4.19%	- 13.09%	13,897	$55.99
VIC	3.06%	- 8.05%	51,323	$49.72

Table 11 shows total demand, production cost and inverse demand elasticity of cost for each region.

Table 11: SNOVIC step 3 demand and costs

Region	Region, demand change%			
	NSW -1%	QLD –1%	SA +5%	VIC +1%
NEM Demand (GWh)	189,335	189,599	190,762	190,593
Production cost ($m)	1955	1959	1990	1982
Inverse demand elasticity of cost	0.661	0.460	0.220	0.703

To calculate the production cost at the post-augmentation equilibrium, we calculate Cq, where the matrix C is the Inverse demand elasticity of cost row from Table 11, and q is the Quantity change column from Table 10. This gives a relative change in costs, over the step 2 case, of 2.0% producing a production cost of $2,008 million.

5.5 AUGMENTATION STEP 5

5.5.1 Elastic demand

Table 12 below shows the calculated surplus and net benefits of the SNOVIC augmentation assuming elastic demand. As expected, the calculated benefits are material at just over $40 million for the 2004/05 year alone, assuming a demand response to a unit price change.

Table 12: SNOVIC benefits assuming demand response ($m)

	Willingness to pay[1]	Production Costs	Surplus
Base ($m)	$19,010	$1,972	$17,037
Augmentation ($m)	$19,086	$2,008	$17,078
Change ($)	$76,227,486	$35,581,645	$40,645,841

1. Willingness to pay is based on an upper price limit of $100/MWh (*P5* in Figure 6).

5.6 EVALUATING THE RANGE OF OUTCOMES

Any modelling exercise, and particularly in one as involved as the current study, requires a large number of assumptions need to be made to produce results. It is standard practice to test the sensitivity of the modelling results and conclusions to realistic variations to key assumptions. The key modelling assumptions have been set out in Section 3. Testing the sensitivity of the results and conclusions to key assumptions is beyond the scope of this study, which is focussed on developing a workable analytical modelling framework for measuring competition benefits arising from interconnects. However, it is practical and sensible to test the modelling results and conclusions to the range of equilibrium outcomes that have been produced.

In game theory, and in *SPARK*, multiple equilibria may be produced at each demand point, and *SPARK* identifies all equilibria given the range of combinations of strategies and strategic players.

In general, the proposed approach would involve comparing the size of economic surpluses 'before' and 'after' the interconnect. However, there are some practical difficulties in doing this:

- it is not immediately clear on what basis the 'before' and 'after' case is being compared. For example, the range and nature of equilibria in the 'before' case will almost inevitably be different than in the 'after' case; and
- it would be necessary to go through each of the calculation steps (steps 1 to 4) set out above for each equilibrium. This is a large task that is outside the scope of this current study..

The proposed approach for evaluating the range of outcomes therefore concentrates on measuring and comparing the *generation costs*, as a proxy for economic surpluses, 'before' and 'after' the interconnect.

To measure these costs, for each of the 60 demand points (see Section 3.6.1) that modelling was undertaken, and for which there are a range of equilibrium outcomes, an equlibria is randomly selected. The generation costs that would result from the pattern of dispatch implied by the set of equilibrium bids are then calculated. This generation cost is then applied to all periods where there was a similar demand level. This process is repeated for each of the 60 representative demand points which, combined, produces a generation cost profile. This process of random selection and generation cost estimation is then repeated 100 times to produce 100 randomly selected cost profiles. These 100 cost profiles are than ranked from the lowest to highest costs. This process is undertaken on the modelling results 'before' and 'after' the interconnect is built.

Once these cost profiles are ranked from highest to lowest, each series can be separated into cost percentiles. This allows two forms of comparison to be undertaken:

- differences between the distribution of generation costs 'before' and 'after' the interconnect; and
- the range of generation costs over all percentiles for either the 'before' and 'after' interconnect cases.

The generation cost estimates for the 'before' and 'after' cases are presented for the 10^{th}, 50^{th} and 90^{th} percentiles only in Table 13. This table shows that there is very little variation within or between the modelling scenarios. For example, the cost estimates vary by less than 1% across the base case or between the 'before' and 'after' case.

Table 13: Distribution of costs and benefits ($m)

	10th percentile	50th percentile	90th percentile
Base case production costs ($m)	$1,965.81	$1,972.33	$1,978.85
Augmentation case production costs ($m)	$1,961.65	$1,968.08	$1,974.52
Cost savings ($m)	$4.16	$4.25	$4.33

The cost savings component of benefits, which would be realised in absence of a demand response, represent $4.25m, or just over 10% of the total benefit of $40 million measured assuming a demand response (see Table 12). This means that the value of additional economic activity in response to lower electricity prices overwhelms the costs savings arising from the interconnect, in this particular case.

6 Conclusions

The empirical estimation of competition benefits from transmission investments is not a straightforward task. Numerous assumptions and approximations need to be made in order to estimate the benefits of interconnection. While this is not unusual in power sector modelling, there is considerably less experience in the industry with the techniques used in the approach set out in this paper compared to other modelling approaches. This is likely to create some initial concern and raise many questions. This will serve to test and improve the approach for measuring competition benefits over time, just as debate has improved the quality of the modelling of other aspects of the power market. Certainly it is better to take steps towards establishing some sensible basis for empirically testing the competition benefits of new interconnects than to ignore these potentially important benefits altogether.

In the interim, it would be advisable to treat the results of this study as an *indicative* as we have not focussed on refining the assumptions and equilibrium as we would normally since the focus of this study was to develop a workable analytical approach to measuring competition benefits.

That said, the framework developed in this report to estimate competition benefits has produced intuitively sensible results. Where there are significant (modelled) constraints (SNOVIC), there are economic benefits arising from their relief.

The SNOVIC augmentation on the other hand, produced material benefits in the order of $40 million in 2004 alone, assuming elastic demand, and about $4.2 million assuming inelastic demand. This means that most of the economic gains come from providing additional consumption possibilities due to lower prices. Again, the price impacts on a regional basis were sensible, indicating price falls in Victoria and SA and price increases in NSW and Qld. These price impacts are consistent with an augmentation that only impacts on interconnection capacity in one direction.

Further, this modelling task assumed that the transfer capacity for each interconnect is at the nominal level. In practice, the transfer capability of interconnects can depend on many variables, including, but not limited to, temperature conditions, generation levels, demand levels and upstream/downstream network constraints/outages. These dependencies can lead to the transfer capability of an interconnect changing from one dispatch interval to the next, and may at times be much lower than the nominal capacity. In this respect, the analysis presented in this report is likely to have understated the potential benefits due to the augmentations (to the extent that consideration of these factors may have produced more hours of constraint in the base case).

The range, or distribution of benefits was analysed for the SNOVIC augmentation under the assumption of perfectly inelastic demand. The distribution of benefits could be more rigorously estimated by taking account of variations in, *inter alia*:

- Demand (e.g. low/high growth, and 10% POE peak);
- Sensitivities on the choice of strategic bidders;
- Sensitivities on the available bidding strategies; and
- Sensitivities on assumed contract levels.

Due to the limited time-frame for the analysis, these sensitivities have not been undertaken.

Note that the benefits estimated in this analysis include all economic benefits and does not separate out competition benefits. An estimate of competition benefits consistent with the ACCC definition could be determined by subtracting the cost-savings attributable to the augmentation (from a competitive dispatch modelling exercise) from this figure.

It should be noted that the above framework ignores any dynamic competition effects, and hence, is at best a partial step towards estimation of competition benefits. Including consideration of the dynamic effects in a net benefits analysis would introduce even more difficulties, and hence more uncertainty in the results produced.

Appendix A.

A.1. Generation assumptions

A.1.1. Existing plant

The generator assumptions shown below represent the current supply conditions and approximate merit order of dispatch by State. Generators and their capacities are those contained in NEMMCO's list of market scheduled generators. Generator's short run marginal costs are those for 2004/2005 from a draft report to the IRPC and NEMMCO by ACIL Tasman. This is the most current publicly available information regarding market-scheduled generators. Prices are presented in real terms in 2003/04 dollars.

Table 14: Power Stations

Station Name	Portfolio	Nominal Capacity / Summer Capacity (MW)	MC
NSW			
Mt Piper	Delta Electricity	1320 / 1320	$12.87
Munmorah		600 / 600	$16.31
Vales Point B		1320 / 1320	$14.81
Wallerawang C		1000 / 1000	$13.94
Eraring	Eraring Energy	2640 / 2640	$15.14
Hume		0 / 29	$0.00
Shoalhaven (Bendeela and Kangaroo Valley)		240 / 240	$0.00
Bayswater	Macquarie Generation	2800 / 2800	$12.28
Hunter Valley GT		44 / 51	$237.71
Liddell		2030 / 2045	$13.39
Redbank	Redbank Project Pty Ltd	151 / 151	$9.51
Blowering	Snowy Hydro Limited	80	$0.00
Smithfield Energy Facility	Sithe Australia Power	160 / 160	$36.58
Victoria			
Somerton	AGL Electricity Limited	157 / 123	$57.13

Station Name	Portfolio	Nominal Capacity / Summer Capacity (MW)	MC
Bairnsdale	Duke Energy Bairnsdale Operations Pty Ltd	92 / 70	$46.20
Jeeralang "A"	TXU	232 / 208	$52.72
Jeeralang "B"		255 / 225	$52.72
Newport		510 / 475	$42.15
Loy Yang B	EME	1040 / 1005	$5.35
Energy Brix Complex	Energy Brix Australia	153 / 144	$9.22
Hume	Eraring Energy	0 / 29	$0.00
Hazelwood	International Power	1645 / 1685	$2.20
Loy Yang A	Loy Yang Power Management Pty Ltd	2110 / 2020	$2.03
Angelsea	SECV	160 / 155	$6.45
Southern Hydro	Southern Hydro Partnership	369 / 435	$0.00
Valley Power Peaking Facility	EME	336 / 280	$51.84
Yallourn W	Yallourn Energy	1470 / 1420	$2.26
QLD			
Callide Power Plant	50% Intergen/50% CS Energy	840 / 840	$11.04
Callide B	CS Energy	700 / 700	$12.12
Swanbank B		500 / 480	$20.44
Swanbank E GT		385 / 355	$29.06
Millmerran Power Plant	Intergen	863 / 853	$7.97
Roma GT Station	Origin Energy Electricity Limited	67 / 61	$52.56
Barcaldine	Enertrade (QPTC)	55 / 53	$68.99
Collinsville		185 / 185	$17.84
Gladstone		1680 / 1680	$15.14
Oakey		320 / 276	$81.96
Mt Stuart GT		294 / 288	$272.98
Townsville GT		160 / 160	$272.98

Station Name	Portfolio	Nominal Capacity / Summer Capacity (MW)	MC
Barron Gorge	Stanwell Corporation	60 / 60	$0.00
Kareeya		72 / 72	$0.00
Mackay GT		33 / 30	$272.98
Stanwell		1400 / 1400	$13.42
Tarong	Tarong Energy	1400 / 1400	$13.08
Tarong North		450 / 450	$11.79
Wivenhoe		500 / 500	$0.00
SA			
Hallett	AGL Electricity Limited	185 / 153	$81.96
Northern	NRG Flinders Operating Services Pty Ltd	530 / 520	$16.43
Osborne		190 / 175	$32.24
Playford		240 / 240	$23.72
Ladbroke Grove	Origin Energy Electricity Limited	88 / 66	$32.99
Quarantine		98 / 89	$61.82
Pelican Point	International Power	490 / 450	$28.23
Dry Creek GT Station		147 / 117	$81.96
Mintaro GT Station		88 / 70	$81.96
Port Lincoln GT		48 / 38	$272.98
Snuggery		42 / 54	$96.65
Torrens Island "A"	TXU	504 / 488	$47.76
Torrens Island "B"		824 / 800	$44.21
Snowy			
Snowy	Snowy	3676 / 3676	$0.00

Source: NEMMCO, *SOO 2003*, 2003; ACIL, *SRMC and LRMC of generators in the NEM – A report to the IRPC and NEMMCO*, April 2003;
Note: Winter capacities from the SOO are taken as the nominal capacity for each power station

A.1.2. Minimum stable generation levels

Table 15 below shows the assumed minimum stable generation levels for coal plant in each region. The model does not allow generation units to run at below this level unless the unit has been shutdown.

Table 15: Minimum stable generation levels

Region	Level (% of capacity)
Coal fired plant	
NSW	40%
VIC	65%
SA	40%
QLD	40%
Gas fired plant	
All regions	15%

Source: IRPC Stage One Report, Proposed SANI Interconnector, July 1999

A.1.3. Ramp rates

Ramp rates were not considered as part of this analysis and power stations were assumed to be perfectly flexible for the purposes of dispatch.

A.1.4. Outage rates

Outage rates are used in *WHIRLYGIG* to derate the capacity of plant. As *WHIRLYGIG* dispatches over an expected demand duration curve (or demand distribution), an average available capacity figure (eg. Derated capacity) is an appropriate treatment of plant outages.

Assumed forced outage rates are shown in **Table 16** below for each region and three plant operation types.

Table 16: Forced outage rates

Region	Base load	Intermediate	Peaking
NSW	2.3%	-	1.32%
VIC	2.2%	-	1.03%
SA	1.85%	1.72%	6.43%
QLD	2.3%	1.72%	6.43%

Source: IRPC Stage One Report, Proposed SANI Interconnector, July 1999

The assumptions relating to planned outages, or maintenance outages, are given in Table 17 below for baseload plant only in each region. Intermediate and peaking plant are assumed to schedule planned outages at times when they would not be required to generate.

Table 17: Planned outages (baseload plant)

Region	Annual maintenance
NSW	17 days
VIC	10 days
SA	32 days
QLD	19 days

Source: IRPC Stage One Report, Proposed SANI Interconnector, July 1999

A.1.5. Hydro plant assumptions

A.1.5.1. Energy constraints

Hydro plants are modelled as energy constrained. Their net output for an entire period is limited by an assumed maximum capacity factor. The hydro units and their energy constraints are listed in Table 18.

Table 18: Hydro plant energy constraints

Station	Portfolio	Energy Budget (capacity factor)	Total Rated Capacity (MW)
Barron Gorge	Stanwell	50%	60
Blowering	Snowy	25%	80
Hume (NSW)	Eraring	50%	25
Hume (Vic)	Eraring	50%	25
Kareeya	Stanwell	35%	72
Shoalhaven	Eraring	6%	240
Snowy	Snowy	15%	3,758
Southern Hydro	Southern Hydro	26%	437
Wivenhoe	Tarong	10%	500

Source: NSW Greenhouse Benchmarks Position Paper, Ministry of Energy and Utilities, December 2001.

A.2. Interconnection assumptions

The NEM is modelled as five main regions (SA, VIC, SNOWY, NSW and QLD).

A.2.1. Inter-regional constraints

A.2.1.1. Constraints

The existing interconnects in the NEM and their transmission capacities are given in **Table 19**. These capabilities are assumed to be constant throughout the modelling period.

Table 19: Interconnection in the NEM

Interconnect Name	Import Capacity (MW)	Export Capacity (MW)
NSW to QLD (QNI)	950	700
Snowy to NSW (SN_N)	1150	3200 (winter) 2800 (summer)
VIC to SA (VIC_SA)	300	460
VIC to Snowy (V_SN)	1500/1900[1]	1100
MurrayLink	220	120
DirectLink	180	180

Source: NEMMCO, *SOO 2003,* 2003

1. V_SN southward capacity is 1500MW for the SNOVIC base case.

A.2.1.2. Losses

Losses are modelled using marginal loss factor equations for flow over the interconnectors listed in Table 19. Intra regional losses are modelled using a static loss factor, which represents the losses between the connection point of a generator and the regional reference node. The most up to date regional static loss factors and marginal loss factor equations from NEMMCO are used.

A.3. Demand side participation

Demand side participation is modelled as operational at times of high prices. Table 20 lists the volume of demand side participation and the price above which it will occur.

Table 20: DSP assumptions

	Volume (MW)	Price ($/MWh)
NSW	31	500
Queensland	25	500
Victoria	150	500
South Australia	89	500

Source: NEMMCO 2003 Statement of Opportunities and Frontier Economics.

6 Conclusions

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