E Modelling of Short-term productive efficiency effects caused by mis-pricing

E.1 Introduction

This appendix presents the analysis conducted by Frontier Economics (Frontier) to estimate the short-term production cost impacts of generator mis-pricing in a price-taking environment.

Given the zonal structure of the NEM and the occurrence of intra-regional system constraints, it is possible for a generator's "shadow" nodal price (the price upon which dispatch is based) to diverge significantly from the applicable regional reference price (RRP) at which the generator is settled. This state of affairs can broadly be referred to as 'mis-pricing' and it implies a disconnect between dispatch, pricing and settlement. When mis-pricing occurs, it is possible for a generator to be either constrained-on or -off by the system operator. By this we mean:

- Constrained-on: a generator is dispatched to some positive level when the RRP is less than the generator's offer price in respect of that quantity; and
- Constrained-off: a generator is dispatched at less than its offered quantity when the RRP exceeds its offer price in respect of that quantity.

Such situations result in a generator potentially:

- Making losses on each unit of output if it is constrained-on and it has bid its plant at marginal cost; or
- Forgoing operating profits in the event that it is constrained-off.

Even in a price-taking environment, a generator that is constrained on or off has the choice of whether to seek to be dispatched or seek to avoid dispatch.

Specifically, if the generator is being constrained-on, it could offer its capacity at $10,000/MWh (VoLL) in an attempt to avoid being dispatched, or bid some or all of its capacity as unavailable. Conversely, a constrained-off generator could offer its capacity at -$1,000/MWh (the market price floor) in an attempt to ensure a higher level of dispatch.

For example, consider a situation where two generators (Gen A and Gen B) are located in a part of a (linear) network where their outputs increase the flow across a particular network element (which has a flow limit of, say, 1,000.1MW). Also assume that demand is 1,000MW and Gen A is bidding at marginal cost (say, $10/MWh) and producing at its maximum of 750MW, while Gen B is also bidding at marginal cost (in this case, $20/MWh) and is producing 250MW. If demand increases and Gen B seeks to increase its output, the flow across the network element will reach its limit (1,000.1MW). If this happens, neither generator's offer price can affect the RRP, because a (further) increase in demand at the RRN cannot be met by an increase in either Gen A or Gen B's output. Under these conditions, the RRP will be set by the offer price of a generator elsewhere in the network. Meanwhile, the value of both generators' output (i.e. their shadow nodal price) will fall below the RRP (at which they are settled) and both generators will be prevented from increasing their outputs – they will be constrained-off. In this situation, Gen B, who is seeking to generate more and receive the RRP, will have an incentive to change its bid in such a way as to increase its dispatch. As it will be settled on the RRP but cannot affect the RRP, it may choose to offer its entire output (say, 750 MW) at below its marginal cost. In fact, Gen B may choose to offer its output at the market floor price of -$1,000/MWh. As this offer price is below Gen A's offer price of $10/MWh, Gen B will be dispatched in its entirety and Gen A will only be dispatched to 250.1 MW, despite the fact that its marginal cost is less than Gen B's marginal cost. Gen A may then seek to regain its output level by itself offering its entire 750 MW capacity at -$1,000/MWh. With both generators bidding at -$1,000/MWh, NEMMCO may apply a tie-breaking rule and dispatch both plant equally at just over 500 MW.

Such 'disorderly' bidding behaviour can potentially result in market inefficiencies. That is, more expensive plant (in terms of marginal cost –- which is Gen B ($20/MWh)) may be dispatched in place of cheaper plant (Gen A –- marginal cost of $10/MWh). By contrast, in a market with no mis-pricing, generators would face no incentives to engage in disorderly bidding because there would be consistency between dispatch, pricing and settlement. In the above example, the cost of mis-pricing would be $2,500/hour (i.e. 250MW x $10/MWh).

Frontier has sought to quantify the magnitude of the dispatch inefficiencies associated with mis-pricing in a price-taking environment. A price-taking environment is one where participants cannot increase the prices they are paid by changing their behaviour. Disorderly bidding can occur in such an environment because participants are simply trying to be dispatched at their preferred level, rather than trying to force up the market price by withholding part of their capacity.

E.2 Methodology

The potential production cost losses due to mis-pricing in a price-taking environment are not straightforward to measure. However, one approach, which we have employed, is to compare the production costs of:

- a base case in which all plant are dispatched at their opportunity cost (e.g. all generators bid full capacity at SRMC) – this is what would occur in a price-taking environment with no mis-pricing; to

- a mis-pricing case where plant have the freedom to bid or offer at VoLL or the market price floor depending on whether they are constrained-on or -off, respectively – this is to capture the incentives for plant to engage in disorderly (but still price-taking) bidding in a market with mis-pricing. This case assumes that generators can predict whether they are likely to be constrained-on or –off prior to submitting their final offer.

This comparison should yield the additional costs of dispatching the market due to mis-pricing.

Note that the analysis applied only to scheduled generation in the NEM and not to non-scheduled generation.

A generator was considered "constrained-on" if dispatched at a level greater than the assumed minimum stable generation level for that plant when the static loss factor adjusted-RRP was less than the short-run marginal cost (SRMC) of the plant. In simple terms, this was a situation where the plant was forced to operate (above the minimum level required to keep the plant on) at below its avoidable costs.

Similarly, a generator was considered "constrained-off" if dispatched at a level below full capacity while the loss-adjusted RRP was greater than the SRMC of the plant. In this situation, and assuming a price-taking environment, the plant operator would prefer the plant to be dispatched at full capacity.

Given the tests for "constrained-on" and "constrained-off" generation described above, the mis-pricing case involved bidding "constrained-on" generation at VoLL ($10,000/MWh) and bidding "constrained-off" generation at the market floor price (-$1,000/MWh) in subsequent iterations.

A tie-breaking rule was employed in situations where the above approach led to multiple generators bidding at either -$1,000/MWh or VoLL. The tie-breaking rule allocated dispatched quantity between the relevant generators (in each region) according to the capacity of each plant. This is consistent with current NEMMCO dispatch procedures.

A number of issues arose in using this methodology:

- Where a particular generator offers to supply at VoLL/Price Floor, this can result in another generator being constrained-on or -off in order to avoid violating the underlying network constraint. This, in turn, may incentivise the second generator to also offer its capacity at VoLL/Price Floor. This problem was addressed by going through a number of iterations of the process described above until no generators were being constrained-on/-off when they offered their capacity at SRMC;

- A generator offering to supply at VoLL/Price Floor can result in an outcome where another offer may be optimal for the generator. For example, if a generator is constrained-on in the initial SRMC run and then offered into the market at VoLL in the first iteration to avoid dispatch, the resultant market outcome may result in a RRP greater than the generator's SRMC (as less capacity has been offered into the market at low prices). As such, the generator may now be foregoing dispatch via its high offer price (VoLL). However, if the generator were offered into the market at SRMC (or the Price Floor) the RRP would again revert to be less than the generator's SRMC and the unit could potentially be constrained-on again. This oscillating outcome feedback loop makes it difficult to determine what offer price the generator would actually adopt in practice.

  Frontier has made the following assumption to deal with this effect: **if a generator is offered into the market at VoLL/Price Floor for a given iteration, then it will continue to be offered into the market at the *same offer price* for all subsequent iterations**. Whilst not ideal, in that this approach does not yield a stable and consistent equilibrium, this assumption resolves the feedback loop issue relatively simply. In the results of the modelling, we found that instances of this outcome were relatively infrequent; and

- Offering multiple generators within a given region into the market at the same offer price (VoLL or the Price Floor) can result in a random generator being dispatched first, depending on the path that the solution algorithm follows in finding the dispatch solution. In other words, an expensive generator (in terms of SRMC) could be dispatched ahead a cheaper generator if they both bid at the same price. This was avoided by imposing tie-breaking rules that ensured that if two or more generators offered into the market at the same offer price, their output must be pro-rated by capacity.

Importantly, we would re-emphasise and highlight that the outcomes yielded by the above modelling approach are not, and do not purport to be, Nash Equilibria. Frontier's usual strategic modelling approach employs Nash Equilibria to ensure that the ultimate bidding strategies are sustainable. However, such an approach was not practicable in the present case because it would have led to results being driven by a mixture of mis-pricing and transient market power. In other words, it would not have been possible to isolate the impact of mis-pricing alone.

E.3 Assumptions

E.3.1 Model

Frontier undertook the dispatch modelling using similar plant and network assumptions as used in its most recent model runs for the Snowy region boundary change proposal modelling undertaken for the AEMC. [280]

Therefore:

- Future plant build was derived using the ***WHIRLYGIG*** model to determine an optimal investment pattern in new generating capacity, which incorporates system reliability limits, greenhouse schemes and other factors that effect investment in the NEM. This pattern of investment was then used as an input to the dispatch/price modelling;

- Dispatch was modelled using the ***SPARK*** model. This model contains the following features:

  – a realistic treatment of plant characteristics, including for example minimum generation levels, variable operation costs, etc;

  – a realistic treatment of the network and losses, including inter-regional quadratic loss curves, and constraints within and between regions;

  – the ability to model systems from a single region down to full nodal pricing, including the incorporation of intra-regional constraints (such as the ANTS constraints); and

[280] This included net clamping of QNI/DirectLink and Heywood/MurrayLink. See Appendix B of AEMC 2007, Abolition of Snowy Region, Rule Determination, 30 August 2007, Sydney.

– the capability to optimise the operation of fuel constrained plant (e.g. hydro plant), and pumped storage plant over some period of time.

However, unlike the case for the Snowy boundary modelling, the strategic bidding module of SPARK was not used in the present modelling exercise.

E.3.2 Generation plant capacities and expansion

Existing and committed generation capacities for scheduled generators were taken from *NEMMCO, Statement of Opportunities for the National Electricity Market, October 2006* (the SOO). The portfolio structure of existing generation was based on *NEMMCO, List of Scheduled Generators and Loads, 21 February 2006* adjusted for those portfolios where dispatch rights have recently been transferred under contract or via sale.

In terms of new plant build, in all regions, we observed a significant amount of 'green' generating capacity being built, including technologies such as hydro, biomass and wind. This capacity was predicted to be built to meet the growing demand for green generation brought about by the greenhouse schemes active in the NEM, as well as to ensure system reliability.

Beyond green investment, some additional peaking and mid-merit generation capacity was needed in each region for reliability purposes over the modelling period. The Tallawarra power station fulfilled this role in NSW, while generic new capacity was required in the other regions.

In NSW and Victoria, peaking capacity was the only additional capacity that was required. In Queensland, new CCGT capacity was needed, predominantly to meet the Queensland 13% gas target. In SA, mid-merit capacity was the most cost effective way to meet load growth and reliability constraints.

E.3.3 Generation costs

Thermal generation SRMC and new entrant plant SRMC and fixed costs were drawn from the ACIL document: *SRMC and LRMC of Generators in the NEM, February 2005*. An updated version of this document was published in early 2007, however the 2005 version was used to maintain consistency with previous modelling analyses undertaken for the AEMC.

E.3.4 Contract levels

Contracts were not incorporated into the modelling, as they would not have affected the bids that were applied.

E.3.5 Modelling period

Financial year 2007/08 was modelled.

E.3.6 Demand

The electricity demand in each year was based on the medium growth, 50% probability of exceedance (POE) forecasts from NEMMCO's 2006 Statement of Opportunities (SOO). The demand profile was based on the 2004/05 actual load profile.

E.3.7 Loss factors and equations

The modelling was conducted on a zonal basis, six regions were modelled: NSW, Queensland, Victoria, South Australia, Tasmania and Snowy. Within each region static losses where accounted for by incorporating each generating unit's Static Loss Factor (SLF) as published by NEMMCO. Inter-regional losses were incorporated dynamically in the modelling using loss factor equations provided by NEMMCO. Static marginal loss factors and dynamic marginal loss factor equations were taken from a pre-release draft version of NEMMCO's document, *List of Regional Boundaries and Marginal Loss Factors for the 2006/07 Financial Year, March 2006*.

E.3.8 Constraint equations

The constraints for the Snowy region were taken from NEMMCO's document, *Constraint List for the Snowy CSP/CSC trial, March 2006*. This document lists the constraints for which Snowy Hydro receives CSP payments, including re-oriented formulations if applicable.

The constraint equations for all other constraints were taken from the Constraint Spreadsheet provided with the *Annual Transmission Statement (ANTS)* data attached to the NEMMCO 2005 SOO. The full list of system normal, national transmission flow path (NTFP) constraints was included in the modelling. The 2005 SOO data were used in this analysis rather than the more recent 2006 SOO data to maintain consistency with previous analyses undertaken for the AEMC.

These constraint equations incorporated the effect of likely transmission network upgrades via changes in line ratings over time.

E.3.9 Interconnectors

The analysis used a six region representation of the NEM: Queensland, NSW, Snowy, Victoria, South Australia and Tasmania.

The interconnector transfer capabilities were limited by the network constraints represented in the ANTS and the Snowy constraint list under system normal conditions. Basslink was assumed to be fully commissioned from the commencement of the modelling period, with limits of 590MW north or 300MW south, consistent with the detailed information provided with the 2006 SOO. MurrayLink, DirectLink and Basslink were dispatched as regulated interconnectors. For Basslink, this was justified on the basis that this would equate to behaviour in a price-taking environment.

E.3.10 Outages

The modelling was conducted on a system normal basis, meaning it did not include any outages (scheduled or random). This was done to increase flexibility for the gaming analysis and is consistent with the assumption that significant generator outages are unlikely to be scheduled during the peak summer and winter months, which were the focus of the modelling analysis. Random or forced outages were excluded from the analysis for simplicity. While this would tend to understate dispatch costs, the *comparison* between the Base scenario and the other scenarios should not have been significantly influenced by this simplification, as the pattern of outages should not be any different between the three scenarios.

E.3.11 Energy-constrained plant

Hydro plant was modelled to reflect long-term average energy limitations, rather than the recent drought conditions that have become more apparent over the last 12-18 months. Run-of-river plants were assumed to operate at the same level across all demand periods and other hydro plants were assumed to run to meet annual energy budgets, based on the assumption that water would be used at times it was most valuable. The modelling also incorporated pumping units (Wivenhoe, Shoalhaven and Tumut), which were assumed to have a 70% pumping efficiency and be dispatched when optimal (i.e. most valuable).

Snowy Hydro was assumed to have an energy budget of 4.9 TWh p.a. as reported in NEMMCO's 2005 ANTS report.

E.3.12 Clamping

Clamping to manage negative settlement residues was assumed to occur bi-directionally on all interconnectors. The only exception was southward flows on the Victoria-Snowy interconnector, where the re-orientation of the constraints to Dederang ensured that no negative residues arose.

Clamping was modelled assuming a $6,000 per hour threshold for negative settlement residues and perfect foresight. That is, if a given combination of market participant bids and offers resulted in negative settlement residues in excess of the threshold arising on a particular interconnector the set of bids was re-dispatched with flow on the interconnector constrained to zero.

Where two interconnectors exist between two regions (i.e. NSW-Queensland (QNI and DirectLink) and Victoria-South Australia (Heywood and MurrayLink)), clamping was only implemented in the case that the *net* negative settlement residues across *both* interconnectors was greater than the threshold.[281]

[281] For example, if negative settlement residues of $X arose on DirectLink and positive residues of $Y arose on QNI then DirectLink would not be clamped if X<Y and would be clamped if X > Y + threshold.

E.4 Results

E.4.1 Overview

Four modelling iterations under the mis-pricing case were required before no generators were constrained-on or -off. Production costs due to disorderly bidding were $8.01m higher than in the SRMC base case. To put this in perspective, actual total production costs across the NEM are greater than $1.7bn for the year. Therefore, the increase in production costs due to mis-pricing was 0.47%.

The results presented in this note suggest that the dispatch inefficiencies arising from mis-pricing in a price-taking environment are relatively small.

The modelling gave rise to no instances of supply shortfalls in either the SRMC base case or the mis-pricing case.

Tie-breaking rules were employed as required for plant bidding at -$1,000/MWh. Tie-breaking rules for multiple plant bidding at VoLL were not required as these generators were not dispatched in any of the analysis. Had they been dispatched, a tie-breaking rule would have been employed.

E.4.2 Cost impact breakdown

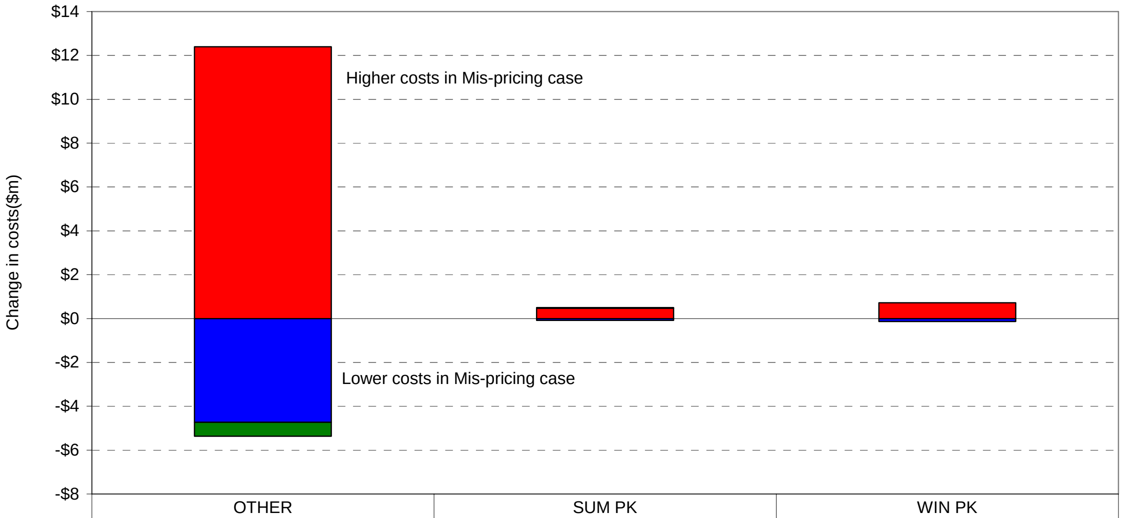
Production cost increases were observed in the mis-pricing case compared with the SRMC base case. These increases arose from increased dispatch of more expensive black coal-fired generation in NSW. Figure E.1 shows the change in production costs relative to the SRMC case by region and time of year. A positive value on the chart indicates a higher cost in the mis-pricing case.[282] Two features are apparent:

- The majority of the cost increases due to mis-pricing occurred during the "other" times of the year. This was to be expected given that these times constituted 90% of the year by hours and as such represented the majority of dispatch over the year;

- Cost increases were observed in NSW at all times of the year, particularly during the other times for the reasons discussed above. These increases arose from increased output of more expensive NSW black coal-fired plant and were partially offset by production cost savings in Queensland and South Australia. This was because greater levels of generation in NSW resulted in the displacement of generation in Queensland and South Australia and a corresponding reduction in production costs in these regions.

[282] Note that the summer and winter peak times were not the usual market definitions of "peak" but rather represent "super-peak" times and were used in the modelling Frontier conducted in assessing the Snowy regional boundary change options.

Figure E.1 Change in production costs by region and time of year ($m pa)



	OTHER	SUM PK	WIN PK
SA	-$0.6	$0.0	$0.0
QLD	-$4.7	-$0.1	-$0.1
NSW	$12.4	$0.5	$0.7

Time of year

Figure E.2 and Figure E.3 show the change in output by plant and the change in production costs by plant, respectively. Again, a positive value on the chart represents a cost increase in the mis-pricing case. Cost increases were a result of increased dispatch for Wallerawang C, Eraring and Stanwell that arose due to these plants bidding -$1,000/MWh for a significant proportion of the year. Reductions in output and cost were also observed for a number of plants (right side of the figures). This occurred because of the tie-breaking rule that was implemented in the modelling. In the mis-pricing case, for a significant number of hours, plant such as Bayswater and Munmorah would bid -$1,000/MWh, as would plant such as Eraring. The tie-breaking rule would then ensure that output was pro-rated amongst the group, resulting in the dispatch of Eraring at the expense of Bayswater and Munmorah. In the SRMC case, the cheapest plant would be dispatched to their full capacity. The net effect of these changes in dispatch was an increase in production costs in the mis-pricing case.

Figure E.2 Change in output by plant type (GWh)

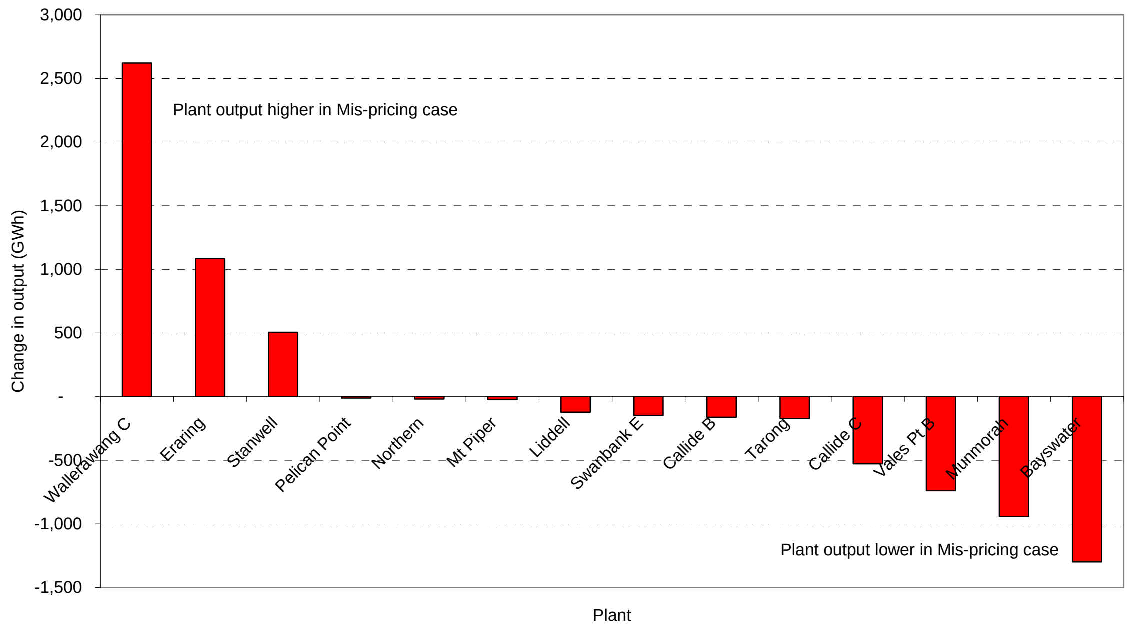
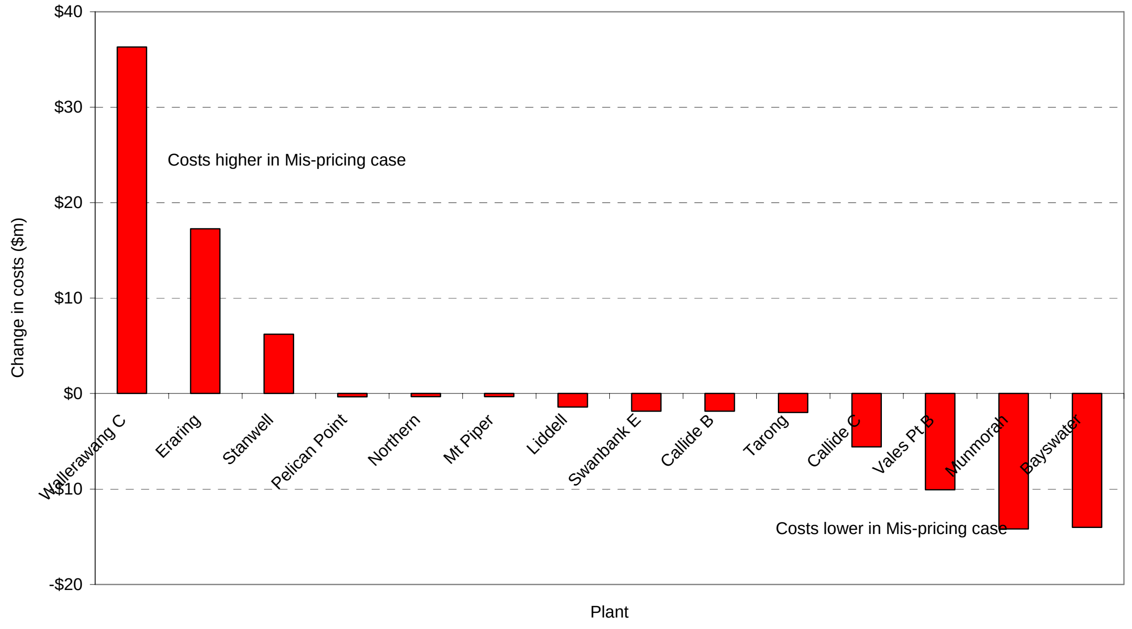


Figure E.3 Change production costs by plant type ($m)



E.5 Comparison to AER measure

It is worth making some observations comparing the measure produced by Frontier's modelling with the congestion costs calculated by the AER for its indicators of market congestion reports.[283] The AER's measure of the Total Cost of Constraints (TCC) was $66 million in 2005-06, $45 million in 2004-05 and $36 million in 2003-04. The TCC is intended to be:

> "…an indicator of the increase in economic welfare that would occur if all congestion on the transmission network were removed. It does this by measuring how much the dispatch cost (that is, the cost of producing sufficient electricity to meet total demand) is increased by the presence of transmission constraints." [284]

Further:

> "Dispatch costs are measured by adding up the marginal costs of producing each megawatt of energy". [285]

The AER chose to estimate generator marginal costs by using generators' bids. It recognised that generator bids may not reflect their underlying resource costs, particularly when a generator is constrained-on or –off and engages in disorderly bidding. The AER also recognised that generator marginal costs could be approximated on the basis of engineering assessments. However, the AER believed that this would involve a significant degree of judgment by the regulator.

The AER described it modelling approach as follows:

> "To calculate the TCC, NEMDE is run to determine which generators are dispatched using actual bid data. The price of each bid is then multiplied by the quantity dispatched (at that bid price) and summed to give a total cost of dispatch. This calculation is done for two scenarios, with and without constraints. The TCC is the difference in the total cost of dispatch with and without constraints." [286]

There are a number of key differences between the Frontier measure of mis-pricing costs across the NEM and the AER TCC measure.

First, Frontier attempted to estimate the welfare costs of mis-pricing alone, not the welfare costs of constraints more generally. While constraints can cause mis-pricing to occur in a regional market, the absence of mis-pricing does not mean that constraints have no costs to the market. This difference is highlighted by considering that the Frontier measure would be equal to zero in a market with full nodal pricing. By contrast, as the AER's TCC measure is calculated on the basis that generator bids remain unchanged, it may yield a positive TCC figure even in a market with full nodal pricing.

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283 See Australian Energy Regulator, *Indicators of the market impact of transmission congestion, Decision*, 9 June 2006 and the AER's annual reports on these indicators (eg Report for 2005-06, February 2007).

284 AER, *Indicators of the market impact of transmission congestion, Decision*, 9 June 2006, p.16.

285 AER, *Indicators of the market impact of transmission congestion, Decision*, 9 June 2006, p.16.

286 AER, *Indicators of the market impact of transmission congestion, Decision*, 9 June 2006, p.13.

Second, Frontier's approach assumed generators' actual marginal costs were the same as the estimates published by ACIL (see above). As noted above, the AER's TCC measure assumes that generators' actual bids reflected their marginal costs.

Third, the approach to demand was different. Frontier used 40 pre-selected demand points reflecting a selection of 50% probability-of-exceedence demand levels, while the AER used actual demand points that arose in each dispatch interval.

Fourth, the network was modelled differently. The Frontier modelling assumed no network outages – it used only system normal constraints – while the AER measure assumed the network as it was in reality during each dispatch interval. For this reason, the most appropriate AER measure comparison with the Frontier results would be the AER's TCC minus the outage cost of congestion (OCC). For 2005/06, the AER measure of the OCC was $27 million, so the AER's net cost of congestion (total costs less outage costs) would be $39 million. This is still well above Frontier's measure of just over $8 million.

In short, the two measures do not set out to measure the same thing and hence are not directly comparable.