B Prevalence and materiality of congestion in the NEM

This appendix presents evidence and summarises on the prevalence and on the economic impact (or "materiality") of network congestion in the NEM for the period from 2001 to 2007. It maps out where, when, and for how long congestion occurred, and reveals prevailing patterns and trends. It also discusses the split between congestion that occurred under system normal conditions and congestion that occurred during outage events.

Patterns of congestion in themselves provide little insight into the effect of congestion on economic efficiency. The occurrence or expected occurrence[60] of congestion does not necessarily equate to its having a material economic impact. It is therefore important to find and analyse evidence on both the prevalence and the materiality of congestion in order to assess the costs and benefits of policy options for changing the Rules relating to congestion management.

Interpreting the evidence is a matter of judgement, and it is important to recognise the characteristics and limitations of different forms of evidence. One particularly challenging aspect of the evidence on congestion is the extent to which participant behaviour would be different if the Rules (and therefore the economic incentives driving behaviour) were different. It is possible that the current Rules induce behaviour that masks *some* types of evidence on congestion while magnifying *others*. Awareness of these potential sources of bias is an important part of interpreting this evidence base. Limitations with the data are discussed in more detail below with reference to specific data sets.

B.1 Analytical framework

This section discusses our approach to measuring the prevalence and materiality of congestion in the NEM.

Indicators of prevalence

There is a large body of evidence on the frequency, duration and location of congestion in the NEM and on the patterns of congestion that have evolved over time. The two principal sources of evidence used in this Review are:

- binding constraints; and
- mis-pricing.

A *binding constraint* refers to a constraint equation (a mathematical representation of the transmission network's physical capabilities and limitations) when it binds, i.e. when it represents the fact that the flow of electricity along a transmission line has reached the line's limit. The frequency and duration of a binding constraint gives an indication of the frequency and duration of congestion at that point.

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60 Expected congestion can be a problem to the extent it affects generator behaviour.

Mis-pricing occurs when there is a difference between the putative local price of supply (i.e. the theoretically "correct" price at each connection point, otherwise known as the "nodal shadow price") and the regional reference price (RRP). The frequency, duration and magnitude of this difference provides a measure of the significance of intra-regional congestion.

Mis-pricing can be either "positive" or "negative". Positive mis-pricing is when a generation connection point is paid *more* than its marginal offer price; hence the generator is likely to be "constrained-off" when a constraint binds. Negative mis-pricing is when a generation connection point is paid *less* than its marginal offer price; hence the generator is likely to be "constrained-on".

Indicators of economic materiality

To build a rounded picture of materiality, we considered evidence on a range of indicators of the economic costs of congestion in the short-term and the long-term. We considered how congestion has affected:

- productive (or dispatch) efficiency;
- risk management and forward contracting; and
- dynamic efficiency.

Productive efficiency refers to the aim of operating the electricity system on a "least cost" basis, given the available network and other infrastructure. In practice, this means generators should be dispatched in a manner that minimises the total system costs of meeting consumers' demands. To what extent, then, does the presence of congestion add to the cost of meeting demand for electricity in the short-term? Congestion might be considered material if less congestion would enable a much cheaper mix of generation to be used to meet demand.

Risk management and forward contracting refer to the trading risks that market participants have to manage, as well as the financial tools available to them to do so. How significant an influence does congestion have on the financial risks that market participants need to manage, and how effective are the tools for managing those risks? Congestion might be considered material if it represented a significant risk to be managed and if available risk management tools were ineffective, such that the ability of parties to contract forward was unduly hindered.

Dynamic efficiency refers to the maximisation of ongoing productive and allocative efficiency[61] over time, and is commonly linked to the promotion of efficient longer-term investment decisions. Dynamic efficiency concerns the efficiency of decision-making and market outcomes over time, when network, load and generation infrastructure can change. To what extent are investment decisions distorted away from behaviour consistent with least-cost outcomes by the presence of congestion or

61 Allocative efficiency means electricity production and consumption decisions are based on prices that reflect the opportunity cost of the available resources.

by the management of congestion in the NEM? Congestion might be considered material if it and/or the management of it did not promote efficient long-term investment decisions in generation capacity, transmission infrastructure, or load.

B.2 Sources of data

We considered evidence on binding constraints, mis-pricing, risk management and forward contracting, and productive and dynamic efficiency from NEMMCO, the AER, Frontier Economics, Dr Daryl Biggar, IES, and from market participants. Each of these sources is introduced below.

- Data on the number of hours of binding constraints within each region and between regions are published annually in NEMMCO's SOO-ANTS.

- Data on the dispatch costs of congestion, including detailed information on each individual network constraint, are published annually by the AER.[62]

- Dr Darryl Biggar calculated intra-regional "mis-pricing"—the difference between "nodal shadow prices" and the regional reference price (RRP)—to measure the extent of congestion within regions over the period 2003/04 to 2005/06.[63]

- NEMMCO extended the analysis undertaken by Dr Biggar in order to cover a larger study period (2001/02 to 2005/06) and to identify the causes of trends in mis-pricing.[64] This analysis focussed on: what was causing the increasing incidence of mis-pricing; whether the trend was likely to continue; and what proportion of mis-pricing was caused by system normal conditions and what proportion by outage events.

- NEMMCO conducted a further study to develop a more detailed picture of intra-regional mis-pricing and its causes.[65] This study focussed on: whether the move to fully co-optimised constraint formulation systematically affected the incidence or duration of mis-pricing; what the distribution of "positive" and "negative" mis-pricing was; and what the proportions of mis-pricing were when comparing outage and system normal constraints.

- Frontier Economics (Frontier) modelled and estimated the impacts of mis-pricing on production costs in the short term.

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62 Australian Energy Regulator, *Indicators of the market impact of transmission congestion*, Report for 2003/04, 9 June 2006; Report for 2004/05, 10 October 2006, Report for 2005/06, February 2007, and Report for 2006/07 was published in November 2007.

63 Dr Biggar's report, "How significant is the mis-pricing impact of intra-regional congestion in the NEM?" (25 October 2006), is available on the AEMC website.

64 NEMMCO's report, *Impact of Intra-Regional Constraints on Pricing* (9 March 2007), is available on the AEMC website. http://www.aemc.gov.au/electricity.php?r=20070416.124114.

65 NEMMCO's report, *Additional Analysis into the Impact of Intra-regional Constraints on Pricing* (August 2007) is available on the AEMC website. http://www.aemc.gov.au/electricity.php?r=20071010.173831.

- The IES study considered the potential future dynamic efficiency impacts of more granular congestion and transmission pricing arrangements in Queensland.

The following sections discuss each of these data sources in more detail.

B.2.1 NEMMCO SOO-ANTS data on National Transmission Flow Paths

In its annual SOO-ANTS, NEMMCO publishes a series of indicators measuring flow path utilisation and historical congestion. The Annual Network Transmission Statement (ANTS) provides an integrated overview of the current state, and potential future development, of National Transmission Flow Paths (NTFPs)[66] (being the portion of network used to transport significant amounts of electricity between load and generation centres). The ANTS also uses a market simulation model to develop a ten-year forecast of network congestion in order to identify the need for NTFP augmentation from a "market benefit" perspective.[67]

Table 16 in Appendix F from the 2007 SOO-ANTS shows the historical occurrence of hours of constrained inter-regional flows since the commencement of the NEM in 1998.[68] Hours of constrained flows reported in this table are assigned according to the defining limit rather than the direction of actual flow for each directional interconnector.[69] The "directional interconnector" is a conceptual term for the grouping of all network lines connecting the two regions.

B.2.2 AER data on dispatch costs of congestion

The Australian Energy Regulator (AER) has published a series of historical indicators of the dispatch costs of congestion for the years 2003/04 to 2006/07.[70] These reports provide data on the total cost of constraints, the outage cost of constraints, and the marginal cost of constraints. Each constraint event is categorised into either "system

66 A NTFP is defined by NEMMCO as a flow path that joins major generator or load centres, is expected to experience significant congestion across the next ten years simulation period, and is capable of being modelling.

67 Market benefit is a term used in the AER's Regulatory Test to describe the sum of consumer and producer surplus in the NEM. See AER, *Review of the Regulatory Test for Network Augmentations, Decision*, 11 August 2004, Version 2, note (5), p.9.

68 Hours of constrained flow have been reported separately for the Terranora inter-connector (up to 21 March 2006), and the Terranora inter-connector (from March 21 2006). Basslink hours of constrained flow have only been reported for the period of its commercial operation (since 29 April 2006). Murraylink operated as a market network service provider (MNSP) until 9 October 2003, and since then as a regulated inter-connector.

69 For example, if the Queensland-NSW interconnect is constrained by a NSW to Queensland transfer limit, and that limit is -100 MW (i.e. the limit requires flow from Queensland into NSW to avoid violating the limit), this is counted as binding in the NSW to Queensland direction, even though the flow is into NSW at the time. In cases where the limits in both directions are equal (i.e. a particular flow is required to avoid violating one or other of the limits), hours of constrained flow are reported in both directions.

70 Australian Energy Regulator, *Indicators of the market impact of transmission congestion*, Report for 2003/04, 9 June 2006; Report for 2004/05, 10 October 2006, Report for 2005/06, February 2007 and Report for 2006/07, November 2007.

normal" or "outage", and a brief explanation is given as to the cause of the constraint binding.

For each network constraint that affects *inter*-regional flows, the AER publishes the cumulative marginal value and the total hours binding over the year. For each network constraint that affects *intra*-regional flows, the AER publishes total hours binding only. This is because it considers that marginal values for intra-regional flows will have little meaning due to strategic bidding behaviour by a generator when faced with the prospect of being either constrained-on or -off (i.e. bidding at either -$1000 or the value of lost load (VoLL)).

It is important to note that the primary reason the AER publishes these indicators is to better understand the nature of constraints and to inform the development of its service standards scheme for TNSPs. The AER's measures were not developed for the purpose of estimating the economic costs of congestion in the NEM.

B.2.3 Dr Biggar's analysis of intra-regional mis-pricing

In 2006, we invited Dr Daryl Biggar to analyse the extent of congestion within regions. To do this, he measured "mis-pricing" over the period from 2003/04 to 2005/06).[71]

To calculate the nodal shadow prices for each connection point, Dr Biggar used data from the NEMDE.[72] He then calculated the frequency, duration and magnitude of deviations between these nodal shadow prices and the RRP. In this way, his measure of mis-pricing indicates the extent to which different generators may be affected when constraints bind.[73] However, his analysis did not seek to assess how generators may have bid if they had faced the correct locational price, nor did it attempt to measure the full effect of congestion on the economic efficiency of dispatch.

Dr Biggar found that the NEM-wide incidence of mis-pricing had been increasing since 2003/04, both in terms of the *average hours of mis-pricing* at specific generator connection points and the *number of connection points* experiencing mis-pricing. He considered mis-pricing to be a frequent and enduring issue at a relatively large number of connection points, claiming that around 95 connection points had been mis-priced for more than 100 hours per annum on average over the three-year period. He concluded that if creating new regions were the only mechanism for managing intra-regional congestion and eliminating mis-pricing, the number of

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71 This study was not able to classify negative or positive mis-pricing for situations where a generator is constrained by an equality constraint. This type of constraint is unclassifiable, because the sign of marginal costs of the constraint are not stored in the NEM databases. Equality constraints tend to be applied for operational reasons to control one generator's output (i.e. for non-conformance or system security reasons).

72 The theoretically correct nodal shadow price at a location is equal to the RRP less – for every binding constraint equation – the constraint marginal value times the coefficient for the connection point in that constraint equation.

73 The analysis on mis-pricing ignores loss factors. This does not affect results on the incidence and duration of mis-pricing data.

pricing regions in the NEM would need to be increased substantially, possibly to around 70.

B.2.4 NEMMCO's first analysis of intra-regional mis-pricing

In light of Dr Biggar's work, we decided further analysis was required in order to assess the likely future trends of mis-pricing. In particular, we sought answers to these questions:

- What has been causing the increasing incidence of mis-pricing, and is this trend likely to continue?
- What proportion of mis-pricing is caused by system normal conditions and what proportion by outage events?
- What are the economic costs of mis-pricing?

We therefore asked NEMMCO in 2006 to extend the analysis undertaken by Dr Biggar in order to cover a larger study period (2001/02 to 2005/06) and to identify the causes of trends in mis-pricing.

NEMMCO calculated two measure of mis-pricing:

- the number of mis-priced connection points; and
- the average duration of mis-pricing for each region over the period 2001/02 to 2005/06.

NEMMCO removed any constraints not relevant to congestion from the study dataset. These included frequency control ancillary service (FCAS) constraints and identified Network Support Agreement (NSA) constraints.[74]

NEMMCO's preliminary study confirmed Dr Biggar's finding that there had been an increasing trend in mis-pricing from 2003/04 onwards. However, the study also showed that over the analysis period from 2001/02 to 2005/06 the number of connection points experiencing mis-pricing had been fairly steady, remaining within a band of 120-140 in total across the NEM. In terms of the average annual duration of mis-pricing at each of those connection points, NEMMCO concluded that there had been a sharp decline from about 160 hours in 2001/02 to 40 hours in 2002/03, followed by a gradual increase to just over 60 hours in 2004/05 and then to about 110 hours in 2005/06. The average duration of mis-pricing was highest in NSW and Queensland, and lowest in Victoria and Tasmania.

[74] In a submission to us, Powerlink stated that constraint associated with the implementation of NSA should be excluded from the analysis since network support is an efficient response to network congestion under the regulatory test. Powerlink noted that if the constraints associated with the NSA within the Queensland region are excluded, then the incidence of mis-pricing reduces from 300 hours to 160 hours for the 2005/06 year. Powerlink, Draft Report submission, 6 November 2006.

NEMMCO listed a range of possible reasons for these trends in mis-pricing and noted that most of the reasons were specific to the region and the situation at the time. NEMMCO also commented that the transition to a fully co-optimised formulation would have contributed to the increase in the frequency and duration of mis-pricing.

B.2.5 NEMMCO's analysis of intra-regional mis-pricing

In 2006 we invited NEMMCO to extend its study of intra-regional mis-pricing and its causes. This study covered the period 2003/04 to 2005/06 and focussed on three specific questions:

- Has the move to a fully co-optimised constraint formulation systematically affected the incidence or duration of mis-pricing?
- What is the distribution of "positive" and "negative" mis-pricing?
- What are the proportions of positive and negative mis-pricing when comparing outage and system normal constraints?

NEMMCO used as case studies five areas of the network where it considered congestion to be an issue: Bayswater, in northern NSW; Hazelwood, in the Latrobe Valley, Victoria; Ladbroke Grove, in South Australia; Gladstone, in central Queensland; and Townsville, in northern Queensland.

The key findings of this analysis are in four parts:

1. distribution of positive and negative mis-pricing;
2. annual average price impact of positive and negative mis-pricing, by region;
3. classification of causes of mis-pricing into "transmission outages" and "system normal events"; and
4. number of mis-priced dispatch intervals with regional reference price > $1 000/MWh.

B.2.6 Frontier Economics' analysis of mis-pricing costs

Following Dr. Biggar's and NEMMCO's analyses of the prevalence of mis-pricing in the NEM, we decided that further analysis was required to understand the economic costs of mis-pricing. For this reason, we asked our Review consultants, Frontier, to estimate the impacts of mis-pricing on production costs.

Frontier's analysis attempted to calculate the dispatch inefficiency costs caused by generators bidding in a "dis-orderly"' manner to avoid being either constrained-on or -off in a market experiencing mis-pricing, in system normal conditions, and assuming otherwise competitive (i.e. short run marginal cost (SRMC)) bidding.

B.2.7 IES' modelling of more granular arrangements for congestion and transmission pricing

IES prepared a consultancy report for the LATIN group on the potential future dynamic efficiency impacts of more granular congestion and transmission pricing arrangements in Queensland.[75] This report estimated the extent of dynamic inefficiencies under the current Rules arising through the sub-optimal location and timing of generation and transmission investment, using Queensland as a case study.

B.2.8 Interpreting the data

Before reading through our review of congestion in the NEM, it is important to understand how to interpret the data presented by NEMMCO, Dr Biggar and the AER, and in particular what its limitations are.

Data is classified as *inter*-regional or *intra*-regional

The data on constraints has been categorised as either *inter*-regional or *intra*-regional. Transmission line constraints that cause price separation between regions have been categorised as inter-regional constraints. Constraints that relate to network limitations only within regions are classified as intra-regional constraints.

NEMMCO's mis-pricing analysis relates to congestion occurring between a generator's connection node and the RRP. Although this analysis has been categorised as intra-regional, mis-pricing at the generator connection node could reflect inter-regional congestion. There is therefore some inconsistency in terminology between the NEMMCO mis-pricing analysis and the AER and NEMMCO SOO-ANTS data.

Fully co-optimised constraints blur the inter-/intra-regional distinction

Since mid 2005, following a direction from the MCE, NEMMCO has been changing the formulation of all constraints to "fully co-optimised".[76] The increased use of fully co-optimised constraints may have affected the analyses of historical data. This is because this form of constraint blurs the distinction between inter-regional and intra-regional constraints, as it can simultaneously restrict the flow across numerous interconnectors and generation in several regions; in a small number of cases intra-regional constraints have actually merged with inter-regional constraints. In some instances, it is, therefore, difficult to assign to one interconnector or one region. For the purposes of the AER Reports and NEMMCO SOO-ANTS, constraints of this type have been attributed to the interconnector most affected by the constraint. Consequently, before definitive conclusions on intra-regional congestion can be reached, it will be important to monitor future trends.

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[75] IES (for the LATIN Group), *Modelling of Transmission Pricing and Congestion Management Regime*, 22 December 2006.

[76] NEMMCO has converted all system normal constraints to the fully co-optimised form and is converting outage and other constraints as required.

Constraints are classified as "system normal" or "outage"

The data also categorises constraints into those that occurred under "system normal" conditions or under "outage" conditions. System normal conditions are those where a generator is constrained by a constraint classified by NEMMCO as a system normal constraint. Outage conditions are those where a generator is constrained by a constraint classified by NEMMCO as an outage constraint. There are also unclassified conditions, where the cause of the constraint cannot be identified.

These constraint classifications are based on NEMMCO's current constraint text descriptions. They may lack precision, however, as there are situations when a binding system normal constraint has been caused by an outage event elsewhere on the network. Furthermore, earlier constraint descriptions may not strictly conform to NEMMCO's present naming conventions.

The data does not include all occurrences of congestion

The data does not include situations where congestion arises but is already being addressed by means which avoid transmission constraints binding through the dispatch process. These include the use of network support agreements (NSAs) to avoid constraints, such as those used in North Queensland, or operational measures by market participants to avoid a constraint binding and causing price separation. Generators that can affect whether or not a particular constraint binds may have the incentive and ability to adjust their generation in such a way as to ensure that the constraint does not bind. For example, under the current regional structure, generation at Tumut may have an incentive to withhold output to prevent the Tumut-to-NSW interconnector from binding, thereby allowing it to access the higher NSW price. In these circumstances, the actual incidence of congestion might understate the issue.

One-off events can distort "trends"

Drawing conclusions from the data about long-term trends needs to be done with care. This is because what appear to be trends can be significantly influenced by one-off events. For example, the number of hours a constraint binds for can be influenced by unforeseen transmission outages. Similarly, generation patterns across the NEM are currently being affected by the drought, and this is also likely to affect the incidence of binding constraints. In this context, Powerlink wrote to us noting that the drought has led to reduced water allocations to South Queensland generators, which in turn will lead to an increase in the incidence of binding constraints on the Queensland network, particularly at the Tarong limit and the Central Queensland to South Queensland limit.[77]

In addition, during 2006/07 the Heywood interconnector, Murraylink and the Basslink all experienced an increase in constrained hours for power flows into

[77] Powerlink letter to John Tamblyn, 13 March 2007. "Output restrictions by SQ generators and Transmission constraints". Available on AEMC website.

Victoria. It is likely that this resulted from recent drought conditions that placed restrictions on generating capacity in the Victoria and Snowy regions.

Such events need to be taken into account when interpreting the data.

B.3 Review of evidence on the prevalence of congestion

Our findings on the incidence and trends of congestion in the NEM are informed by the hours binding data in NEMMCO's SOO-ANTS and by the AER's assessment of binding constraints in its annual reports on the impact of congestion.

B.3.1 Inter-regional congestion

B.3.1.1 NEM-wide results

There has been an increase in the total hours of binding constraints on interconnectors since NEM start. Hours rose steeply from 2 139 hours in 1998/99 to 9 925 hours in 2000/01. This was followed by a sharp fall to 2 398 hours in 2001/02, which was caused by a reduction in outages hours binding on the Queensland-to-NSW interconnector (QNI) of 6 400 hours. Since then there has been a steady rise from 6 781 hours in 2002/03 to 12 849 hours in 2006/07 (or 8 242 hours excluding Tasmania).

Constraints binding under both system normal and outages conditions have increased since 2001/02. Hours of binding for system normal constraints rose significantly from 1 351 hours in 2001/02 to 4 965 hours in 2003/04 and remained relatively constant at around 4 750 hours until 2006/07 when the hours of system normal binding constraints increased to 9 013. A major contributing factor was an extra 4 000 hours binding on the Victoria-to-Tasmania interconnector.

Hours of outage constraints binding have oscillated between 3 913 and 2 530 since 2002/03 and tend to account for under 40 per cent of total inter-regional binding each year. Outages were the predominant cause of congestion only on the Murraylink and Terranora[78] interconnectors and on flows from Snowy to NSW during 2006/07.

Since the start of the NEM, the split between outage and system normal constraints binding has varied, as have the trends in hours binding for each directional interconnector. Flows between Victoria and South Australia on the Heywood interconnector consistently accounted for the highest number of hours binding. Murraylink and Terranora have the next highest incidence of binding constraints. Flows between Snowy and NSW in both directions have the lowest incidence. The incidence of constrained hours on exports from Queensland grew significantly from 2004/05 to 2006/07.

[78] Previously referred to as Directlink.

B.3.1.2 Results by interconnector

Queensland — NSW (QNI and Terranora)

Since QNI was commissioned on 18 February 2001 the transfer capability from Queensland to NSW has increased progressively from 300 MW to the current capability of 1 078 MW (from 12 November 2003). Over the same period there was a significant increase in generation in Queensland; around 1 300 MW of new generation was commissioned. The transfer capability on QNI from NSW to Queensland is 486 MW.

The incidence of Queensland export constraints grew significantly from 2001/02 to 2003/04. There was a slight decrease in congestion in 2004/05 but this was followed by increases in 2005/06 and 2006/07.

Since the commissioning of the QNI interconnector, there has been a significant rise in the hours of system normal constraints binding, increasing from 3 hours in 2000/01 to 1 462 hours in 2006/07. The duration of constraints binding on southern flows due to outages fell from 2 159 hours in 2000/01 to 162 hours in 2003/04; there was subsequently a steady rise to 301 hours in 2005/06 and then it fell back to 199 hours in 2006/07. Flows from NSW to Queensland on QNI rarely bind; for example there were only 23 hours in 2006/07.

The prevalence of binding on the Terranora interconnector was similar to that on QNI: it bound more on southward flows than northward, and until 2006/07 congestion was mostly caused by system normal constraints. Total hours of binding constraints on Terranora southward flows were consistently above 1 200 each year between 2003/04 and 2006/07. Since 2003/04, there has increasing binding of contraints on flows northwards from NSW on the Terranora interconnector. Also since 2003/04 there has been an increase in the proportion of outage constraints (compared to system normal constraints), from 25 to 62 per cent of total binding constraints.

Flows from Queensland to NSW became increasingly constrained in order to maintain oscillatory stability for the loss of QNI. The system normal constraint used to maintain oscillatory stability for the loss of QNI[79] bound on 194 days during 2005/06 for a total of 484 hours, and on 192 days during 2006/07 for a total of 888 hours.

Thermal limits in both Queensland and NSW also constrained flows on both interconnectors. For example, the system normal constraint managing load on the Armidale to Kempsey line bound for 153 hours over 58 days during 2006/07. This constrained around 4 800 MW of generation in the Hunter Valley in NSW. Thermal limits on the Mudgeeraba to Terranora 100 kV and Swanbank to Mudgeeraba 275 kV constrained flows on the Terranora interconnector during high NSW demand.

[79] The limit is set at either 950 MW or 1 078 MW depending on the status of the Millmerran units. With both units online, the higher limit of 1 078 MW applies.

In summary, flows southwards on the QNI became increasingly constrained due to system normal conditions. On Terranora, there was a significant level of binding in both the northward and southward direction, and the relative frequency of outage-caused binding increased. However, network augmentations commissioned in 2006/07 are expected to improve the power transfer capabilities between Queensland and NSW. For example, the Armidale to Koolkhan line uprating completed in December 2006 will allow for increased interconnector power flow in the New South Wales to Queensland direction.

NSW—Snowy

The limit for flows from Snowy to NSW varied between 3 500 MW in winter and 2 800 MW in summer and was dependent upon line ratings, Snowy generation profile and the magnitude of loads in southwest NSW. The limits for flows from NSW to Snowy were determined by thermal and transient stability limits; they were highly dependent on loads in southwest NSW. For example, the Snowy to NSW flows were constrained for short periods at levels of 500 MW and 800 MW, less than the 3 000 MW nominal limit, to avoid overloading lines in southern NSW.

The interconnector between NSW and Snowy experienced the lowest incidence of binding inter-regional constraints in the NEM; but although these constraints were of short duration, they caused significant price separation.[80]

There was an increase in the incidence of binding constraints in both directions under system normal conditions. Hours of system normal binding in the Snowy to NSW direction increased from 2 hours in 2003/04 to 117 hours in 2005/06 and then decreased to 17 hours in 2006/07. In the opposite direction, from NSW to Snowy, the hours of binding constraints increased for both system normal and outages events from 0 hours in 2002/03 to 62 hours in 2006/07. Analysis undertaken for the Abolition of Snowy Region Rule Determination[81] showed that there was a large increase in the frequency of Murray-Tumut constraints binding in both system normal and outage conditions between 2003/04 and 2006/07, affecting flows in both directions.

Also the incidence of binding caused by outage on the Snowy to NSW directional interconnector increased significantly during the past couple of years. This has chiefly been caused by outage events within NSW. For example, an incident on the 77 line south of Sydney resulted in outages on the Snowy-to-NSW interconnector increasing by 50 hours between 2004/05 and 2005/06.[82]

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80 AER, Indicators of the market impact of transmission congestion, Report for 2005 -2006, February 2007, p.5.

81 AEMC 2007, Abolition of the Snowy Region, Rule Determination, Appendix F Historical Congestion between Victoria, Snowy and NSW Regions, 30 August 2007.

82 On 31 October two outages of the 77 line south of Sydney (to repair damage to the 76 line) saw imports across the Snowy interconnector restricted to as little as 300 MW over each outage. Imports from Queensland were also reduced. Extreme prices were experienced in NSW during these outages, largely as a result of the reduced import capability.

Flows between Snowy and NSW were also influenced by the incidence of binding between Victoria and Snowy. The major source of congestion in the NSW to Snowy direction during periods of high demand in Victoria involved a thermal limit for the Upper Tumut to Murray 300 kV line.

Works commissioned in 2006/07 will potentially improve the interconnector transfer capability. Works on the Lower Tumut to Upper Tumut 330 kV is likely to increase the Snowy to NSW thermal limits under most circumstances. Also the control scheme that has been introduced will allow for up to 200 MW of additional flow from Snowy to NSW.

Snowy—Victoria

The incidence of binding constraints during southward flows on the Snowy to Victoria interconnector increased from 62 hours in 2004/05 to 272 hours in 2006/07. This was due to both system normal and outage events. Higher power transfers into Victoria resulting in an increase in binding constraints in 2005/06 were probably due in part to the impact of drought on Victorian hydro-generation. In the two-year period between 2001 and 2003, outage events dominated, accounting for over 80 per cent of total hours of binding constraints. Since 2004, system normal events accounted for over 60 per cent of total hours of binding constraints. On southward flows, there was a significant rise in system normal binding constraints between 2004/05 and 2006/07, from 41 to 172 hours.

Analysis conducted for the Abolition of Snowy Region Rule Determination[83] found that stability constraints were the most frequent limitations on flows along the Victoria to Snowy interconnector, and that 80 per cent of the binding constraints that limit flows in both directions arose under system normal conditions.

There was a significantly higher incidence of binding constraints on flows north from Victoria to Snowy than on flows south into Victoria. The one exception was 2005/06, which was the first year when the Snowy-to-Victoria interconnector was constrained more often. Hours binding for the Victoria-to–Snowy directional interconnector rose steadily from 207 hours in 1998/99, peaked at 1 201 hours in 2003/04, then fell significantly to 578 hours in 2006/07. Most of this decrease was due to a lower incidence of system normal constraints binding.

Discretionary constraints were applied from 2003/04 to 2005/06 and had a high market impact. In 2005/06 the most significant market impacts occurred on three days: 9 November and 7 December 2005 and 2 February 2006. Prices in NSW on all three days exceeded $5 000/MWh, whilst the Victoria-to-Snowy interconnector was limited to as low as zero by constraints invoked by NEMMCO to manage counter-price flows. Prices in Victoria and South Australia at the time were often as low as $30/MWh.

83 AEMC 2007, Abolition of the Snowy Region, Rule Determination, Appendix F Historical Congestion between Victoria, Snowy and NSW Regions, 30 August 2007.

Two key measures have been implemented to address counter-price flows around the Snowy region: the Snowy CSP/CSC trial, which commenced in October 2005; and the Southern Generator's Rule, which came into effect in September 2006 and alters the distribution of settlement residues between the two Snowy interconnectors. Furthermore, in August 2007 we released our decision to abolish the Snowy region.[84] The abolition of the Snowy region will take effect on 1 July 2008. Of these measures, only the CSP/CSC trial was in place in time to affect the indicators in this data.

South Australia—Victoria (Heywood and Murraylink)

The most frequently binding inter-regional constraint in the NEM was the Heywood interconnector between Victoria and South Australia.

Until 2006/07, congestion on the Heywood interconnector mainly affected flows from Victoria to South Australia. The interconnector rarely bound in the opposite direction. However during 2006/07 flows from South Australia to Victoria were constrained for 630 hours, a significant increase from only 25 hours in the previous year. This reflected the changing use of the interconnector caused by the drought impacting on Victorian generators.

Most of the congestion on the Heywood interconnector was caused by the inherent limits of the network. The major source of congestion on flows from Victoria to South Australia was the thermal limit for the 500/275 kV transformers at Heywood. Flows from South Australia to Victoria were chiefly constrained by the thermal limit for the South Morang 500/330 kV transformer.

The increase in wind farm output has led to a reduction in the Victoria to South Australia transient stability limit. The revised co-optimised formulations and increased output from wind farms have resulted in a much lower transfer limit on the interconnector than was previously the case.

Although the interconnector bound for significant periods, the market impact of congestion on the Heywood interconnector tended to be low. The Cumulative Marginal Value (CMV)[85] fell from $423 129 to $221 371 during 2005/06.

The duration of outages caused by congestion decreased. Between 2004/05 and 2005/06 the hours of outage constraints binding decreased from 1 426 hours to 377 hours. During 2006/07, outages caused Heywood to bind for 577 hours.

Several major outage events resulting in constraints on the Heywood interconnector occurred during the period 14 March 2005 to 1 June 2005. On 14 March 2005, Northern Power Station units 1 and 2 simultaneously tripped, resulting in an overload on the Heywood interconnector, which subsequently tripped. This simultaneous loss was re-classified as a credible contingency event by NEMMCO,

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[84] Ibid.

[85] The CMV for a constraint is the sum of the marginal constraint value for every five minute dispatch interval over a year.

which resulted in a lower import capability into South Australia, binding for 918 hours. The re-classification was removed on 1 June 2005.

The Murraylink interconnector also bound significantly in both directions, with constraints mainly caused by outages. For flows from Victoria to South Australia, the chief source of congestion was the thermal limit for the Davenport-to-Brinkworth line in South Australia. System normal binding constraints fell from 2003/04, reaching 281 hours in 2005/06, but then rose to 416 hours in 2006/07. Outage binding increased from 338 hours in 2003/04 to 551 hours in 2006/07.

Both planned and unplanned outages significantly affected the availability of Murraylink. During 2006/07, Murraylink was out of service for 68 days during the year including a month long outage between 6 January and 9 February.

Flows from South Australia to Victoria rarely bound on the Heywood interconnector but did bind significantly on the Murraylink interconnector. Binding constraints on the Murraylink increased from 162 hours in 2003/04 to 717 hours in 2006/07. This increase was driven primarily by outages (75 per cent of total hours in 2006/07).

In late 2002 and early 2003, following the augmentation of the Victoria-to-Snowy interconnector and the commissioning and operation of the Murraylink interconnector, tests were undertaken to assess the oscillatory stability performance of the power system. Throughout the period of the tests, the capability of the Victoria-to-Snowy interconnector, as well as the combined capability of the Heywood and Murraylink interconnectors, were progressively increased. On 7 March 2003, the oscillatory stability limits of the Victoria-to-Snowy, Heywood and Murraylink interconnectors were increased to the present levels. However, this increase did not result in a fall in hours binding on either the Murraylink or Heywood interconnectors.

The capability from Victoria to South Australia was increased in January 2006 with the service of a very fast runback scheme and installation of 270 MVA of capacitor banks throughout Victoria. These works removed several constraints caused by voltage stability and thermal network limits. Furthermore, TransGrid installed a System Protection Scheme to manage the outage of the Wagga-Darlington point 330 kV line, which removed this contingency as a constraint on Murraylink. Also during 2006/07, wind monitoring equipment was installed on various 220 kV lines in regional Victoria. These developments should help to reduce binding between Victoria and South Australia.

Tasmania—Victoria (Basslink)

Basslink began transferring power in November 2005 and entered into commercial operation in April 2006. The majority of congestion on Basslink was caused by system normal constraints. Flows from Tasmania to Victoria were limited by the thermal limit for the South Morang 500/330 kV transformer and by the over-voltage limit at George Town on a Basslink Trip. In the opposite direction, flows from Victoria are affected by the limit associated with sufficient load being available for the Frequency Control Ancillary Service (FCAS) special protection scheme.

A relatively low level of binding occurred in 2005/06. The number of hours of binding constraints on flows south from Victoria to Tasmania was 205, which was significantly more than the 37 hours of binding constraints on flows from Tasmania to Victoria. Most of the binding constraints in both directions happened under system normal conditions. In 2006/07, there was an extra 4 000 hours of binding on the Victoria to Tasmania flows.

B.3.2 Intra-regional congestion

B.3.2.1 NEM-wide results

The NEM initially suffered significant intra-regional binding, with 7 485 hours in 1998/99 and 12 763 hours in 1999/00.[86] This was mostly caused by outage events in Queensland. The total hours of binding intra-regional constraints across the NEM then fell from 1 960 hours in 2000/01 to 392 hours in 2002/03, rose steadily to 2 082 in 2004/05, and fell slightly to 1 830 in 2005/06. NEMMCO did not publish data on hours of intra-regional constraints for 2006/07.

The proportion of hours binding caused by outage events rose steadily from 50 per cent in 2002/03 to 75 per cent in 2005/06.

NEMMCO's mis-pricing analyses revealed a similar trend. The average annual duration of mis-pricing at each mis-priced connection point showed a big fall from about 160 hours in 2001/02 to 40 hours in 2002/03. This was followed by a gradual increase to just over 60 hours in 2004/05 and then to about 110 hours in 2005/06.

Over the period from 2001/02 to 2005/06, the total number of connection points across the NEM that experienced mis-pricing was fairly steady, staying within a band of 120-140 (out of a total of 278[87]). This means that just under half of all generation connections points experienced some mis-pricing each year.

Annual average price impact of positive and negative mis-pricing

In order to quantify the magnitude of positive and negative mis-pricing, NEMMCO calculated the average annual price difference between the nodal price and RRP at generation connection points. The data is presented with an upper and lower bound to account for the impact of constraint violations.[88] However, these results require careful interpretation because they are influenced by the degree of dis-orderly

86 See Table 5 in Appendix F of NEMMCO's 2006 SOO-ANTS. The 2007 ANTS does not report separately on intra-regional congestion so the information in this section only reflects information through 2005/06.

87 According to NEMMCO's document, "List of Regional Boundaries and Marginal Loss Factors for the 2007/08 Financial Year", there are 278 generator connection points. This includes ancillary services, and generation load connection points plus embedded generators; after excluding these categories there are 212 generation connection points.

88 This analysis is contained in section 3 of NEMMCO's report.

bidding by the generator (i.e. bidding at either VoLL or -$1 000 to prevent being constrained-on or -off).

NEMMCO calculated two measures of the average capped mis-pricing amounts for generation connection points:

1. the average amount for all dispatch intervals in the year; and

2. the average amount for those dispatch intervals when the generator was mis-priced.

The data from (1) gave an estimate of the impact of congestion on generators over the whole year. For example, in 2005/06 in NSW generators that were constrained-off tended to benefit, on average, by between $2 and $6 per MWh (which represented a decrease from between $6 and $12 per MWh in the previous year).

Patterns of variability were evident at other generator connection points. As an indication, only a small number of connection points in the NEM were mis-priced by more than $5/MWh for all three years of the study. These connection points all related to small gas or hydro plants in Queensland. No connection points in NSW were mis-priced by more than an average of $5 (taking the middle of the upper and lower bounds) for more than one year of the study. A large number of Victorian connection points did experience more than $5/MWh of mis-pricing for the first two years of the study, but almost all these impacts declined to less than $1/MWh by 2005/06.

The data from (2) demonstrated that the magnitude of the average capped mis-priced amount for those dispatch intervals when the generator was mis-priced, was significantly greater than the average amounts over the year. For example, in 2005/06 the Victorian generators, which are typically constrained-off, had a positive mis-priced amount of over $550/MWh when subject to mis-pricing, compared to less than a $1/MWh average for the whole year.

These data are clearly influenced by dis-orderly bidding in the market. When a generator is faced with being constrained-off or -on, it has incentives to bid in a manner consistent with seeking to be dispatched (e.g. -$1 000) or seeking to avoid being dispatched (e.g. VoLL). The magnitude of dis-orderly bidding varies across regions.

NEMMCO also calculated the standard deviation for the average capped mis-pricing amounts per incidence of mis-pricing. These figures were very high, showing that there was a high variation in generation bids when constraints bound.

Some market participants stated that the negative effects of pricing mis-match in the NEM may be overstated. The NGF commented that mis-pricing will naturally occur in an "energy-only" market, which is designed to be over-supplied at all times to satisfy system security and reliability standards at moments of maximum peak demand. Furthermore, the NGF suggested that the level of inefficient dispatch under most market conditions, taking account of the typical level of hedge contracts that participants manage, would be less than that indicated by magnitude of price differentials.

While we accept that a greater level of hedge contracts held by a generator should attenuate its incentives to exploit any market power, the level of hedging is unlikely to prevent generators from bidding in a dis-orderly manner to avoid being either constrained-on or -off when a constraint binds. In fact, dis-orderly bidding may occur in order to manage contract positions. The Frontier modelling work estimated the impact of dis-orderly bidding caused by mis-pricing on economic efficiency. This work is discussed in section B.4.1.2.

Mis-priced intervals when regional reference price > $1 000/MWh

NEMMCO also analysed the number of dispatch intervals where mis-pricing occurred while the RRP was more than $1 000/MWh.[89] Data was presented for each connection point over the three years between 2003/04 and 2005/06 for each NEM region.

The purpose of this data was to provide further information on the magnitude of the impact of mis-pricing by considering the incidence of mis-pricing events when the RRP was relatively high. This followed the earlier NEMMCO report which showed that the vast majority of mis-pricing occurred when the RRP was less than $300/MWh.

The data indicated that across the NEM regions there was an increasing trend in the incidence of mis-pricing when the RRP was more than $1 000/MWh. The one exception was Victoria, where there was no mis-pricing when the RRP was above $1 000/MWh in 2005/06. The data also showed that generators within a region tended to be affected equally by mis-pricing in this high price band.

B.3.2.2 Results by region

The data on both binding constraints and mis-pricing showed that there was significant variation in the incidence and trends of congestion across the NEM regions. Each region is discussed below.

Queensland

The majority of Queensland's generating capacity is located in Central and South West Queensland. The main power transfers are from Central Queensland to the north and south, and from South West Queensland to the major load centres in South East Queensland. Since January 2002, the Central–North limit has predominantly been managed via an NSA between Powerlink and generators in Northern Queensland.

Total hours of binding intra-regional constraints fell from 1 289 hours in 2001/02 to 141 hours 2002/03, and then steadily increased, peaking at 1 133 in 2004/05.

89 See section 2 of NEMMCO's report.

From 2002/03 to 2005/06, there was a significant rise in the incidence of binding constraints due to outages. Outage events accounted for the majority of hours binding.

The average hours of mis-pricing followed a similar trend, with the lowest number of hours over the period recorded in 2003/04, followed by a moderate increase since that time. The number of generation connection points being mis-priced was constant, at around 40 to 50 each year. Queensland has 73 generation connection points in total, so this means the majority of generation connection points experienced some mis-pricing each year.

The increase in congestion was predominantly due to increased constraints on flows from Central to South Queensland during both system normal and network outage conditions. The increase in outage constraints binding between 2004/05 and 2005/06 was mainly due to the constraint to limit flows in the presence of storm activity or lightning in Central Queensland[90] and to the constraint used to manage the outage of the Gladstone Bus Tie Transformer.[91]

A system normal constraint limits flows from central Queensland to south Queensland to a maximum of 1 900 MW to avoid transient instability. The constraint affected around 5 700 MW of generation in central and north Queensland (around 60 per cent of the total registered capacity for the region). The incidence of this constraint binding increased over the three years to 2005/06 from 9 hours to 83 hours. In 2006/07, the constraint bound for 82 hours over 39 days during the year, similar to the previous year. Binding of this constraint can have significant market impact. On 27 June the constraint bound for 15 hours during times when the spot prices exceeded $5 000/MWh. The AER estimated the total cost of constraints for this event at $8.1 million. Likewise for a similar event on 2 February 2006, the constraint bound for 12 hours each day with an estimated TCC of $12.7 million. Powerlink commissioned two capacitor banks in November 2005 to address this limit.

Several major augmentation projects in North Queensland have enabled limits between Central and North Queensland to be increased. The limit for flows from Central to North Queensland was increased from 780 MW to 800 MW in late 2001, and was increased again from this 800 MW static limit to a dynamic limit ranging from 925 MW to 985 MW in February 2003. This consequently reduced the incidence of binding for flows from Central to North Queensland. In 2006, however, Powerlink

90 This system normal constraint limits flows from Central to South Queensland to a maximum of 1 200 MW in the presence of storm activity or lightning in Central Queensland. This condition leads to the reclassification of the loss of the double circuit between Tarong and Calvale as a credible event. The constraint directly affects around 5 700 MW of generation in Central and North Queensland or around 60 per cent of the total registered capa city for the region. The constraint bound for a total of 24 hours over 14 days during 2005/2006. On 30 November 2005 the constraint bound for 5 hours. The AER TCC measure reached $2.2 million on this day.

91 This constraint limits flows from Central to South Queensland to a maximum of 1 700 MW. It is used in conjunction with Q_GLD34_500 to manage the outage of the Gladstone Bus Tie Transformer. The constraint directly affects around 5 700 MW of generation in Central and North Queensland or around 60 per cent of the total registered capacity for the region. The constraint bound for a total of 63 hours over 15 days during 2005/2006.

decreased the limit down to 810 MW after the Townsville gas turbines became base load units and the list of critical contingencies was reviewed.

In 2006, the transfer limit in Far North Queensland was increased from 192 MW to 286 MW as a result of the installation of the Woree static var compensator. However, the effects of Cyclone Larry led Powerlink to reconfigure the network to overcome long-term damage, resulting in a decrease in the transfer limit to 268 MW for 2007.

Electricity usage in Queensland has grown strongly in recent years. Over the past 5 years, state-wide growth in summer maximum demand was 31 per cent, including a record growth of 42 per cent in South East Queensland. In response, over the last decade, Powerlink built 25 new substations and more than 2 600 km of new transmission lines.

The rapid growth in demand, the development of transmission and the commissioning of new generation mean that the pattern of intra-regional constraints has changed rapidly. For example, the Tarong constraint contributed to 16.8 per cent of the total hours of binding constraints in 2001/02, but has not bound since. This can be attributed to the many augmentations (such as capacitor banks, line rearrangements, and new lines) in South East Queensland.

The combination of transmission and generation investment and the NSA, which is operating in Northern Queensland, dampened the increasing trend in congestion.

NSW

The NSW high voltage transmission network was designed to transfer power from the coal-fired power stations in the Hunter Valley, Central Coast and Lithgow areas to the major load centres. The network was also designed to transmit the NSW/ACT share of Snowy generation towards Canberra and Sydney. The development of the NEM and interconnection with Queensland have increasingly imposed a wider range of loading conditions on the network than was originally planned.

NSW imports a significant share of its generation from the surrounding NEM regions. As a result, most congestion in NSW affects imported flows; and, compared to other regions, it has a relative low incidence of intra-regional hours binding. Between 2000/01 and 2005/06, the total hours of binding intra-regional constraints were as low as 40 hours and as high as 180 hours. Most of these hours binding were attributable to outage conditions. NEMMCO's mis-pricing analyses for NSW showed a similar trend to that of Queensland. The level of mis-pricing reached the lowest level over the period considered in 2003/04, when it was around 50 hours on average for each mis-priced generation point. It then steadily increased over the following years to over 170 hours in 2005/06. The number of generation points affected by mis-pricing was relatively constant, ranging between 22 and 25 points over the sample period. This means that around half of the 52 generation points in NSW experienced mis-pricing each year. Twenty generation points consistently experienced more than 50 hours of mis-pricing between 2001/02 and 2005/06.

Between 2003/04 and 2005/06, constraints managing flow on the 82 line (and to a lesser extent the 81 line) dominated. The majority of binding dispatch intervals occurred during planned network outages on the 81 line between Liddell and Newcastle. This constraint did not bind during 2006/07.

Outages elsewhere on the network contributed to the incidence of binding intra-regional constraints. In 2003/04, planned outages of the 22 line between Vales Point and Sydney North occurred on 9 days of the year. In 2004/05, the Regentville to Sydney West line was taken out of service on 5 days.

Also in 2004/05, the system normal constraint which manages flows along the Western Sydney transmission ring had significant impact, affecting dispatch for 41 hours during the year. The constraint caused generation at Mount Piper to be constrained-off and generation at Wallerawang to be constrained-on. However, in both 2003/04 and 2005/06 there was little incidence of this constraint binding.

In summary, between 2003/04 and 2005/06 the incidence of intra-regional congestion in NSW increased and was primarily driven by outage events. Outage of the 81 line between Liddell and Newcastle occurred consistently during the period. 2006/07 saw a marked decrease in the occurrence of intra-regional congestion.

Snowy

The Snowy region provides a crucial transmission link in the middle of the NEM. Snowy Hydro is the major provider of peaking generation during periods of high demand in Victoria and NSW. The transmission grid within the Snowy region and between NSW and Victoria was designed to deliver energy from the Snowy Mountains to major load centres and to connect the state-based power systems in NSW and Victoria. A key feature of the Snowy region is that it is generation rich; it contains virtually no load. Hence, virtually all the electricity generated by the Snowy generators is exported to other NEM regions. The critical transmission elements between Murray and Tumut are the 65 and 66 lines. Thermal limits on these lines mean that the loading of one line has to be protected against the potential loss of the other. These thermal limits are what largely determine the typical 1 350 MW transfer limit across the Murray–Tumut cut-set of lines. There are multiple lines from the Snowy region into NSW and Victoria, with a substantially higher transfer capacity from Snowy to NSW (commonly 3 100 MW) than from Snowy to Victoria (in extreme circumstances a maximum of 1 900 MW).

In the Snowy region most of the mis-pricing was the result of outage events. The region experienced a significant increase in the average number of hours of mis-pricing per mis-priced connection point due to both system normal and outage constraints. The number of connection points mis-priced under system normal conditions and outage conditions doubled from 2 in 2004/05 to 4 in 2005/06.

Victoria

The Victorian transmission system operates at voltages of 500 kV, 330 kV, 275 kV and 220 kV. The 500 kV network primarily transports bulk electricity from generators in the Latrobe Valley to the major load centre of Melbourne, and then on to the major smelter load at Portland and the Heywood interconnection with South Australia. A strongly meshed 220 kV transmission network supplies the metropolitan area and the major regional cities of Victoria. The 330 kV network interconnects with the Snowy region and NSW. The 275 kV transmission line from Heywood interconnects with South Australia. The key intra–regional constraint is between the Latrobe Valley and Melbourne.

Hours of binding intra-regional constraints in Victoria were relatively consistent and low over the period considered, peaking at 255 hours in 2004/05. In 2005/06 there were 111 hours of binding intra-regional constraints in total, of which 106 were at times of system normal operation.

The mis-pricing data also showed a relatively low incidence of congestion within Victoria. The trend in mis-pricing in Victoria was quite different to that in Queensland and in NSW, with the average hours of mis-pricing peaking at around 75 hours in 2003/04 and then falling to 20 hours in 2005/06. Of the 64 generation points in Victoria, 45 experienced mis-pricing in 2003/04, and 18 of these experienced over 160 hours. In 2005/06, the number of generators experiencing mis-pricing dropped to 30, and no generator experienced mis-pricing for more than 20 hours.

The constraints that predominantly resulted in mis-pricing were those that manage flow across the Hazelwood Terminal Station 500/220 kV transformers.

Prior to 2003/04 the constraints managing the flow across the Hazelwood transformers (V>V1NIL & V>V2NIL) accounted for most of the hours of binding constraints within the Victoria region and caused significant congestion on the dispatch of the 2 600 MW generation in the Latrobe Valley. After 2003/04 the number of hours binding for these constraints decreased dramatically, dropping from 163 hours in 2003/04, to 101 hours in 2004/05, to 105 hours in 2005/06. This was primarily driven by a change in generation ownership, which improved the coordination of affected generation.

A further constraint (V>V4NIL) bound for 91 hours in 2005/06 and again for 101 hours in 2006/07 but did not bind in any of the years before then. This constraint equation limits output from the Hazelwood Nos. 3, 4, and 5 generation units to ensure that pre-contingent flows on the Hazelwood transformer do not exceed its continuous rating. The three units affected by this constraint have a combined maximum capacity of around 650 MW.

Binding of this constraint was caused by the reconfiguration of the Hazelwood power station buses connecting to the transformer following the commissioning of the fourth 500 kV line between Latrobe and Melbourne in August 2005. VENCorp is planning to complete work at the Hazelwood power stations by December 2008, which should alleviate this congestion issue.

Over 95 per cent of Victoria's intra-regional congestion was caused by system normal constraints. There was a sharp drop in the average number of hours of mis-pricing per mis-priced connection point due to both system normal and outage constraints. The average number of connection points mis-priced due to outage conditions fell to nil. The number of connection points mis-priced under system normal conditions remained steady, at about 18 per year. The overall trend in Victoria was a decline in the amount of mis-pricing.

South Australia

South Australia's transmission network comprises four main power transfer corridors: the north distributor, the port distributor, the central distributor and the south distributor. The north distributor provides power transfers between the Adelaide metropolitan area and the northern parts of the State, in particular the power stations at Port Augusta. The port distributor provides power transfers between the power stations located in the Port Adelaide area and Adelaide's northern metropolitan area. The central distributor provides power transfers between the northern and southern regions of metropolitan Adelaide. The south distributor provides power transfers between the Adelaide metropolitan area and the lower south eastern areas of the State.

The considerable generation capacity at the main load centre in Adelaide, combined with the robust transmission network, means that there is little system normal intra-regional congestion in South Australia. Instead, most of the hours binding are due to network outages. In the SOO-ANTS data, outages accounted for all the hours of intra-regional constraints binding between 2001/02 and 2004/05 and 80 per cent of hours binding in 2005/06.

NEMMCO's analyses showed a very low level for the average duration of mis-priced connection points between 2001/02 and 2003/04, but this increased significantly to over 100 hours in 2005/06. The low number of mis-pricing incidents in the initial years was because many of the South Australian constraints were formulated as interconnector-only or option 8 constraints. The change in constraint formulation from interconnector-only constraints to fully co-optimised constraints led to an increase in the reporting of binding constraints.

During the period 2001/02 to 2005/06, the number of South Australian generation connection points experiencing mis-pricing fluctuated between 6 and 16. Compared to other regions, this was a relatively low share of South Australia's total of 41 generation connections points.

NEMMCO reported an increase in mis-pricing in 2004/05, primarily due to a significant increase in NSA/Direction constraints binding on the Snuggery and Port Lincoln units to manage line loading. The number of instances of Snuggery generation being constrained-on dropped considerably in 2005/06. This was due to the adoption of a higher 15-minute rating on the Keith–Snuggery line in December 2004 and to a reduction in line flows because of increasing generation from the Lake Bonney and Canunda wind farms. The constraining-on of Port Lincoln through NSA/Direction also decreased in 2005/06, probably due to output from the Cathedral Rocks wind farm, which commenced generation in June 2005.

In 2005/06 intra-regional constraints bound for around 115 hours, and 14 generators experienced a degree of mis-pricing. The recent addition of significant remote wind generation contributed to congestion on the Heywood interconnector, and this affected the level of mis-pricing at generators in South-East South Australia.[92] A significant planned outage of the LeFerve-to-Pelican Point line added to the level of mis-pricing in 2005/06, with this constraint binding for a total of around 134 hours over 16 days.

In 2006/07, there was only one constraint that bound for more than 10 hours. This was the system normal constraint which constrains generation from Lake Bonney 2 and Snuggery to manage voltage stability on Snuggery fault. There was very little congestion caused by outage in South Australia during 2006/07.

Tasmania

The Tasmanian transmission system consists of a 220 kV bulk transmission network with some parallel 110 kV transmission circuits. It provides power transfer corridors from several major generation centres to load centres, and power transfers between major load centres.

The most common constraints experienced in Tasmania are thermal constraints. To alleviate this problem, Transend have installed weather stations around the grid which enables it to use dynamic ratings.[93] To a lesser extent, lines also have voltage constraints, which occur mostly in the south. In the north, there are limits on the transmission from the Woolnorth windfarm. There are also dynamic stability limits between Farrell and Sheffield during credible events. There is currently an NSA with the Gordon generator to increase generation to meet demand in the south.

The commissioning of Basslink also introduced significant changes to the transmission system loading patterns. Transend lines are operated at N security, rather than N-1. They use an Automated System Protection Scheme to shed load when necessary, which enables the network to facilitate Basslink exports up to its 600 MW limit.

Data on intra-regional congestion only exists from when Tasmania joined the NEM in May 2005. In 2005/06 the total hours binding were 505, the second highest incidence of intra-regional congestion (after Queensland). Most of these hours were due to planned network outages. Again in 2006/07 intra-regional congestion in Tasmania was predominately due to planned outages, either on the Farrell-to-Sheffield line or the Hadspen-to-Palmerston line.

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92 There are currently 6 wind-farms in South Australia with a further 3 being built. The increase in wind farm output has led to a reduction in the Victoria to South Australia transient stability limit.

93 These stations provide real-time measurements every minute. Using real-time measurements, particularly of temperature and wind (as they found hot days often correlated with windy days), has improved the line ratings. This data is sent to NEMMCO to give dynamic real-time ratings. In the case of a weather station failure, NEMMCO uses a backup ratings table with 5° Celsius increments. Transend also monitors the tension in the lines, particularly in the south, to assess whether the lines have iced. If this has occurred, a small current is transmitted to melt the ice.

B.4 Review of evidence on the economic materiality of congestion

To gauge the economic materiality of congestion in the NEM, we considered evidence on how congestion affected:

- productive (or dispatch) efficiency;
- risk management and forward contracting; and
- dynamic efficiency.

B.4.1 Productive efficiency

This section considers the evidence on whether congestion significantly increased the cost of meeting demand for electricity by limiting NEMMCO's ability to make use of the least-cost mix of generation. Evidence on this question comes from data published annually by the AER and from modelling by Frontier Economics on the impact of mis-pricing on the productive efficiency of dispatch. We also took into account the economic modelling undertaken in assessing the Rule changes relating to congestion issues in the Snowy region.

B.4.1.1 AER congestion indicators

In its annual reports on indicators of the dispatch costs of congestion for the years 2003/04 to 2006/07, the AER published data on:

- *Total cost of constraints (TCC).* The TCC estimates the amount by which the cost of supplying load (based on bids and offers submitted) would fall if all transmission constraints were removed. The TCC is calculated by running the NEM dispatch engine (NEMDE) with all network constraints removed, and comparing the dispatch cost under that scenario with the actual dispatch cost; i.e. assuming unchanged bidding behaviour with and without congestion.

- *Outage cost of constraints (OCC).* The OCC is similar to the TCC but only estimates the impact of removing all transmission outage constraints (but retaining other causes of congestion such as system normal constraints). This measure seeks to quantify the dispatch costs of congestion arising solely from network outages. It is calculated by running NEMDE with only "system normal" constraints and comparing the dispatch cost under that scenario with the actual dispatch cost. The AER has developed this indicator in response to the interest shown by retailers, generators and other traders in the TNSPs' management of outages. If the impacts of the outages are not predictable or notified well in advance, it can be difficult for traders to manage the associated risks.

- *Marginal cost of constraints (MCC).* The MCC estimates the amount by which the costs of supplying load would fall if the relevant transmission limit were increased by one megawatt. This measure could assist in identifying which constraints have the largest effect on dispatch costs. It identifies particular elements of the transmission network that have binding limits that cause generation to be dispatched out of merit order The MCC is derived by summing up the marginal constraint values reported for each constraint over the year. MCC data are published for inter-regional constraints only. For intra-regional constraints, only data on the amount of time that a constraint was binding is reported.

All of these indicators, therefore, involve a comparison between actual dispatch costs (based on participants' bids and offers) and hypothetical dispatch costs in circumstances otherwise identical (same bids and offers) except that no congestion occurred.

As noted in the Draft Report, the AER indicators ought to be interpreted with care, as there are important limitations inherent in the assumptions and methodology. Also, the AER measures consider only the dispatch costs of congestion and do not provide any indication as to the costs of reducing these costs, whether by building out constraints or by pricing more congestion than is currently priced.

Table B.1 shows that the TCC measure increased significantly and continued to exhibit a high volatility.

Table B.1 AER indicators of the market impact of transmission congestion

	Total Cost of Constraints (TCC)	Outage Cost of Constraints (OCC)	OCC as % of TCC	TCC Index (2003/04=100)	OCC Index (2003/04=100)
2003/04	$36m	$9m	25%	100	100
2004/05	$45m	$16m	35%	125	178
2005/06	$66m	$27m	41%	183	300
2006/07	$107m	$58m	54%	297	644

Note: The 2005/06 figures include congestion in the Tasmanian transmission network for the first time.

Data source: AER, *Indicators of the market impact of transmission congestion*, reports for 2003/04 (9 June 2006), 2004/05 (10 October 2006), 2005/06 (February 2007), 2006/07 (November 2007).

The AER reported that the number of network constraints significantly affecting interconnector flows increased from 5 in 2003/04 to 40 in 2006/07, while the number of constraints that affected market outcomes within regions on the mainland also increased from 7 to 14 over the same period. By converting the AER's measures into indices with a base year of 2003/04 to allow for comparisons across years, we see a near three-fold increase in the TCC and over a six-fold increase of the OCC in the four years to 2006/07.

The AER commented that the majority of the TCC occurred over a few days during the year. For 2004/05, 70 per cent of the TCC accumulated on just 7 days. For 2003/04, 60 per cent of the TCC accumulated on just 9 days. In both years, these high costs arose on the Victoria-to-Snowy interconnector, or the Queensland-to-New South Wales interconnectors, or the lines from the Latrobe Valley to Melbourne. In 2006/07, two-thirds of $107 million was accumulated on 16 days. In June 2007, the

TCC totalled $46 million, reflecting the tight supply and demand balance caused by the combination of generation outages and high demand.

High-impact inter-regional constraints

Complementing the TCC is the MCC. The AER explains that the TCC is an indicator of the quantum of the total market impact of transmission congestion while the MCC indicates the underlying cost at the margin.

To determine the MCC, the AER examined the marginal value of individual constraint equations over time to identify the particular network elements that contribute to these market impacts. It then classified which inter-regional network constraints had a "high market impact", that is the constraint had a CMV of more than $30 000/MW in a year.

Table B.2 summarises the high impact inter-regional constraints from 2003/04 to 2006/07.

Table B.2 High-impact inter-regional constraints from 2003/04 to 2006/07

	2003/04		2004/05		2005/06		2006/07	
Number of High Impact Constraints	5 (0 Outages)		15 (7 outages)		32 (10 outages)		40 (15 outages)	
Total Hours Binding	1 802		1 963		3 195		4 292	
CMV	$1 035 073		$2 768 162		$7 568 731		$6 144 459	
	System Normal	Outages	System Normal	Outages	System Normal	Outages	System Normal	Outages
Hours Binding	1 802	0	1 332	631	2 551	644	2 722	1 570
% of total hours binding	100	0	67.86	32.14	79.84	20.16	63.42	36.58
CMV ($million)	1.035m	0	2.157	0.611	3.002	4.567	$3.05m	$2.533m
(% of total CMV)	100	0	77	22.1	39.7	60.3	58.8	41.2

Data source: AER, *Indicators of the market impact of transmission congestion*, reports for 2003/04 (9 June 2006), 2004/05 (10 October 2006), 2005/06 (February 2007), 2006/07 (November 2007).

In terms of total hours binding, these high-impact constraints represent approximately 30 per cent of all inter-regional constraints each year. The data show that the measured effects of high-impact inter-regional constraints increased seven-fold over the three years, from a CMV of around $1 million in 2003/04 to $7.6 million in 2005/06. In 2006/07, there was a decline in the CMV to $6.1 million.

The significant increase in high-impact CMV between 2004/05 to 2005/06 from $2.7m to $7.6m was mainly driven by two outage events that affected flows on Murraylink. The two outages were the loss of the Robertson transformer in South

Australia and the outage of the Wagga-to-Yanco line in NSW, which jointly accounted for $3.7 million of the total $7.6 million CMV.

From the series of AER reports, it is also possible to identify whether there are network constraints that consistently bound for a significant duration during the four years. From our review of the data, there seems to be only a small number of constraints which consistently bound during the four years. The majority of these constraints were system normal. This demonstrates that many constraints have a relatively short life-cycle and that the location and nature of constraints with a high market impact can vary across years.

For example, the system normal limit on the Heywood interconnector for flows from Victoria to South Australia continued to bind for around 1 000 hours each year, even though its CMV fell from $423 129 in 2004/05 to $167 597 in 2006/07. Also the system normal limit on Victorian exports caused by the South Morang limit in the Latrobe Valley continued to bind for around 100 hours each year, but its market impact diminished significantly from $439 527 in 2003/04 to $6 139 in 2005/06 but then increased to $537 751 in 2006/07.[94]

Notwithstanding these limitations, the AER estimates are of a very small magnitude compared to the NEM's annual wholesale sales of $6-11 billion. Importantly, the more recent AER reports have indicated that an increasingly significant proportion of the TCCs are related to transmission outages and that the majority of the costs occurred on only a few days per year.

B.4.1.2 Frontier Economics' modelling of short-term productive efficiency effects caused by mis-pricing

We commissioned Frontier to conduct further analysis to estimate the impacts of mis-pricing on production costs in the short-term.

Background

Frontier sought to quantify the magnitude of the dispatch inefficiencies associated with mis-pricing in a price-taking environment. Frontier's analysis attempted to calculate the dispatch inefficiency costs caused by generators bidding in a "dis-orderly" manner to avoid being either constrained-on or -off in a market

94 Previously the constraints managing the flow across the Hazelwood transformers (V>V1NIL & V>V2NIL) accounted for most of the hours binding within the Victoria region, which caused significant congestion on the dispatch of the 2 600 MW generation located in the Latrobe Valley to Melbourne. However, there was a dramatic decrease in 2005/06 in the number of hours binding for these constraints; the total hours decreased from 163 hours in 2003/04 and 100 hours in 2004/05 to 14 hours in 2005/06. This was driven by a change in generation ownership which improved the coordination of the operation of the affected generation. A further constraint (V>V4NIL) was binding for 91 hours in 2005/06 but did not bind in any of the years before then. This was caused by the reconfiguration of the Hazelwood power station buses connecting to the transformer following the commissioning of the fourth 500 kV line between Latrobe and Melbourne in August 2005. VENCorp is planning to complete work at the Hazelwood power station by December 2008 which should result in an improved bus arrangement and alleviate this issue.

experiencing mis-pricing. This analysis was limited to production cost impacts in a price-taking environment—that is, in the absence of any market power being exercised. A price-taking environment is one where participants cannot increase the prices they are paid by changing their behaviour.

Dis-orderly 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. This means that generators that were not mis-priced were assumed to bid their capacity into the market at their short-run marginal cost (SRMC). Meanwhile, generators that were constrained-on were assumed to bid their capacity at $10 000/MWh to avoid being dispatched, and generators that were constrained-off were assumed to bid their capacity at -$1 000/MWh to seek to be dispatched.

Methodology

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

- A *base case* is where 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.

- A *mis-pricing case* is 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 dis-orderly (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. The analysis applied only to 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 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 when the static-loss-factor-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 these tests for constrained-on and constrained-off generation, 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 provide incentives for 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 or -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 being 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 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, Frontier found that instances of this outcome were relatively infrequent.

- 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 of 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, the outcomes yielded by this 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 bidding strategies are sustainable. However, such an approach was not practicable in this 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.

Assumptions

Model

In the dispatch modelling, Frontier used plant and network assumptions similar to those used in the model runs it did for us when assessing the Snowy region change proposal:[95]

- Future plant build was derived using the ***WHIRLYGIG*** model to determine an optimal investment pattern in new generating capacity. This incorporates system reliability limits, greenhouse schemes and other factors that affect 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

  – 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 in the Snowy region modelling, the strategic bidding module of SPARK was not used in this modelling exercise.

Generation plant capacities and expansion

Existing and committed generation capacities for scheduled generators were taken from NEMMCO's SOO, October 2006. The portfolio structure of existing generation was based on NEMMCO's *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, Frontier observed that a significant amount of "green" generating capacity was 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.

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95 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.

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 per cent gas target. In South Australia, mid-merit capacity was the most cost effective way to meet load growth and reliability constraints.

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.

Contract levels

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

Modelling period

Financial year 2007/08 was modelled.

Demand

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

Loss factors and equations

The modelling was conducted on a zonal basis, with six regions modelled: NSW, Queensland, Victoria, South Australia, Tasmania and Snowy. Within each region static losses were 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.

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 us.

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

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 590 MW north or 300 MW 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.

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.

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 the times it was most valuable. The modelling also incorporated pumping units (Wivenhoe, Shoalhaven and Tumut), which were assumed to have a 70 per cent pumping efficiency and to be dispatched when optimal (i.e. most valuable).

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

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-to-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 to Queensland (QNI and DirectLink) and Victoria to South Australia (Heywood and MurrayLink), clamping was only implemented in the case that the *net* negative settlement residues across *both* interconnectors were greater than the threshold.[96]

Results

Overview

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

The results presented 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.

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 B.1 shows the change in production costs

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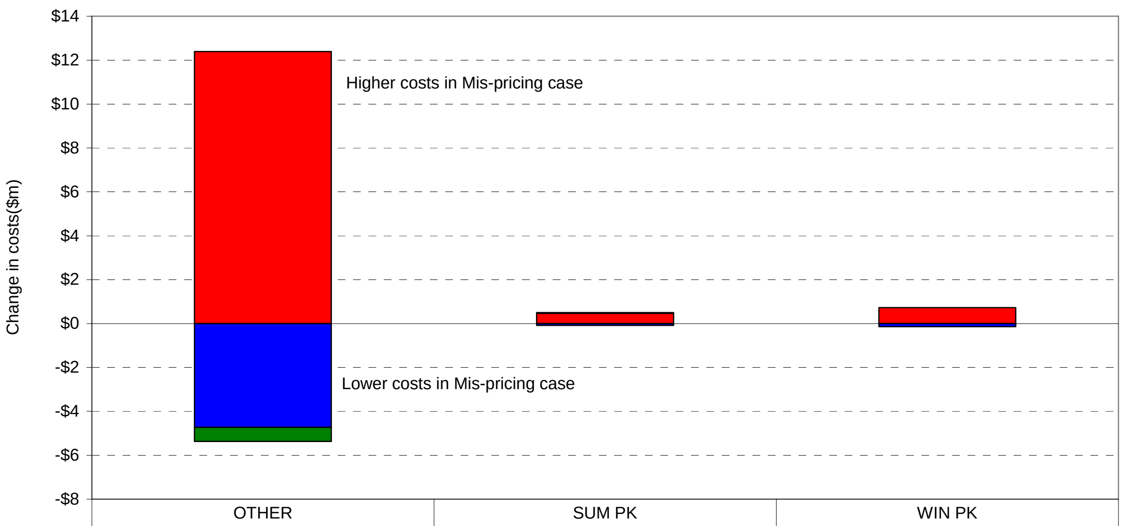
96 For example, if negative settlement residues of $X arose on DirectLink and positive residues of $Y arose on QNI then DirectLink would not be clamped if X<Y and would be clamped if X > Y + threshold.

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.[97] 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 per cent 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.

Figure B.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

Figure B.2 and Figure B.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).

97 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.

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 B.2 Change in output by plant type (GWh)

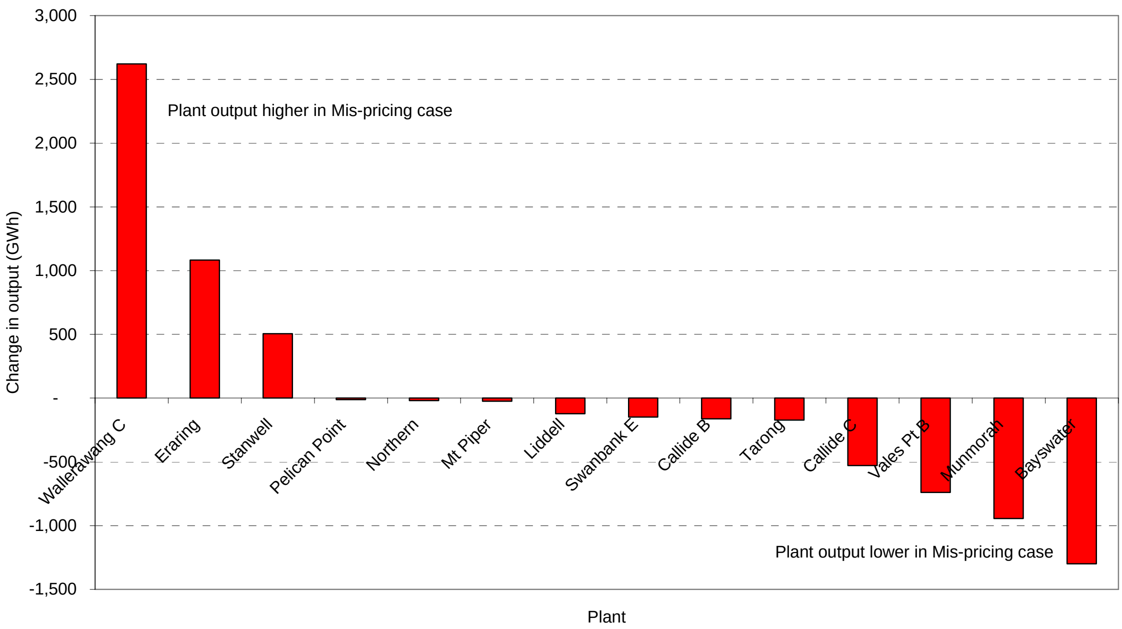
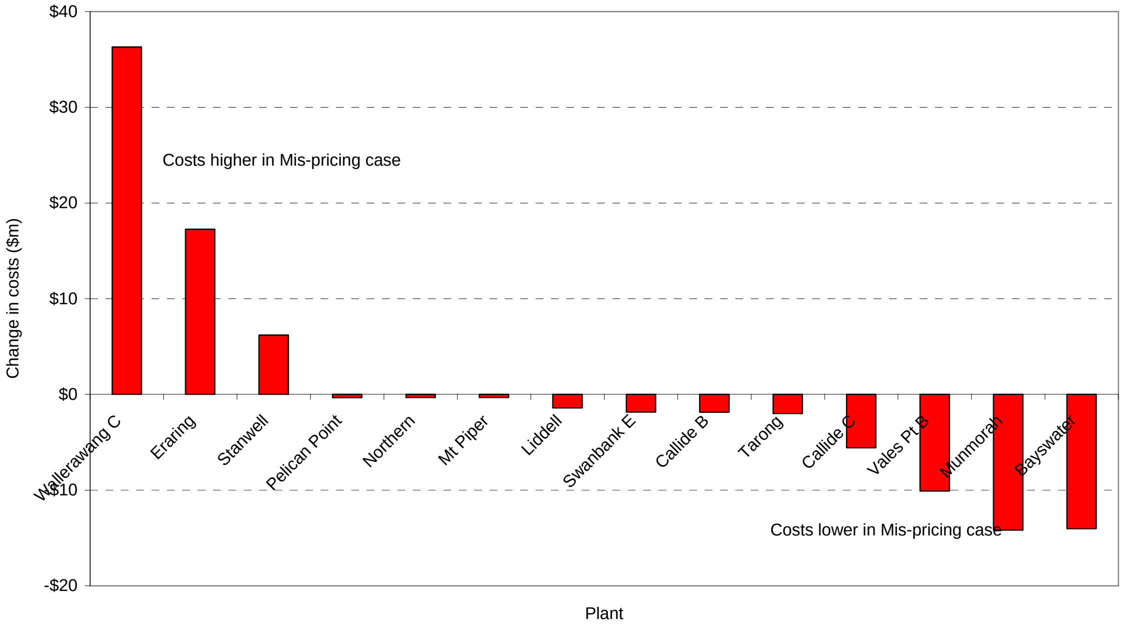


Figure B.3 Change production costs by plant type ($m)



Comparison with AER measure

It is worth making some observations comparing the measure produced by Frontier's modelling with the congestion costs calculated by the AER.[98] The AER's measure of the 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.[99]

Further:

> Dispatch costs are measured by adding up the marginal costs of producing each megawatt of energy.[100]

The AER chose to estimate generator marginal costs by using generators' bids. It recognised that generators' bids may not reflect their underlying resource costs,

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[98] 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).

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

[100] Ibid.

particularly when a generator is constrained-on or -off and engages in dis-orderly bidding. The AER also recognised that generator marginal costs could be approximated on the basis of engineering assessments; however, it believed that this would involve a significant degree of judgment by the regulator.

The AER described its 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.[101]

There are a number of key differences between Frontier's measure of mis-pricing costs across the NEM and the AER's 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 generators' bids remain unchanged, it may yield a positive TCC figure even in a market with full nodal pricing.

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 per cent 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 comparison of the AER measure with the Frontier results would be the AER's TCC minus the 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.

[101] Ibid.

Qualifications

There are limitations to the modelling undertaken by Frontier. As with most modelling, the assumptions and methodology were necessarily simplified. The assumptions of price-taking behaviour, the ability of generators to predict their dispatch conditions and the approach for addressing consequential impacts of disorderly bidding on other generators were all made to limit the scope of the analysis. That being said, the results do give an indication that the impact of binding constraints on productive efficiency is relatively low.

B.4.1.3 Frontier's economic modelling of congestion in the Snowy Region

We published our Final Rule Determination on Snowy Hydro's Rule change proposal to abolish the Snowy region of the NEM in August 2007. We also published Final Rule Determinations on alternative options for addressing congestion in this area in November 2007. We believe it is worthwhile to recount the results of the dispatch modelling undertaken to support our analysis of those proposals on the basis that the Snowy region has been recognised as a key location of congestion in the NEM.

Frontier's dispatch modelling was based on an accurate description of the NEM network, load and generation plant configuration and allowed for certain generators to bid strategically by withholding a portion of their capacity where it was profitable to do so. For the purposes of clarification, we note again that this differs from the price-taking approach applied by Frontier in its modelling of mis-pricing costs (discussed above).

The modelling compared the Abolition proposal against a base case and several alternative proposals. The base case comprised the existing regional boundary structure with scope for NEMMCO clamping or re-orientation to avoid counter-price flows on the Victoria-to-Snowy interconnector. Other alternatives modelled were the Snowy Split Region option proposed by Macquarie Generation, in which Murray and Tumut are placed in their own regions (with Dederang used as the RRN for the Murray region), as well as an option proposed by the Southern Generators' group, which mimicked the current congestion management arrangements in the Snowy area (existing regional boundaries, plus the CSP/CSC at Tumut and the Southern Generators' Rule). It would be reasonable to suggest that this last proposal allowed the least scope for mis-pricing of Snowy Hydro generation out of all the competing alternatives.

The modelling found that moving between any of the scenarios in an environment allowing for strategic bidding led to relatively small differences in the underlying resource costs of dispatch. For example, the least-cost option in the "low contract" case in 2010 (Abolition) was only $1.53 million per annum cheaper than the highest-cost option (Southern Generators' proposal). Incidentally, this highlights that in an environment of strategic bidding, reducing or eliminating mis-pricing need not promote dispatch efficiency.

In our view, the modelling work illustrates that the dispatch efficiency impacts of eliminating mis-pricing, even in an environment of strategic bidding, are likely to be relatively small compared to the overall level of trade and welfare surpluses in the NEM.

B.4.2 Risk management and forward contracting

Congestion can contribute to participants' trading risks, creating a variety of risks that they have to manage. The nature of these risks, and the effectiveness of the tools available for managing them, are important considerations in assessing the economic materiality of congestion. The quantification of these impacts, however, is very difficult in part due to the availability of public data on how individual companies manage risk. This section considers the evidence on the extent to which congestion poses significant risks to market participants, and whether there are material deficiencies in the available tools for risk management.

Congestion can contribute to price volatility, both within a region as well as with respect to RRP divergences between regions. Such volatility can create financial risks for market participants. The NEM has a high level of price volatility in comparison with other electricity spot markets. This could be due to a number of factors:

- the design of the market
- volatility of demand
- transmission constraints
- generator bidding patterns.[102]

Studies have measured the extent of price volatility in the NEM. Firecone published figures on the mean and standard deviations of price separation across regions for 2005 (see Table B.3). This shows that, at times, regional prices separate and the resulting price differences are highly volatile.[103]

Table B.3 Mean and standard deviation of price separation across regions

	NSW-QLD	NSW-VIC	VIC-SA	Snowy-NSW	Snowy-VIC
Mean $/MWh	8.1	4.8	-6.2	-5.3	-0.5
Standard Deviation $/MWh	172.1	264.0	123.6	178.3	156.1

[102] In the southern states, demand during periods of prolonged hot weather can be substantially due to high air-conditioning load. This effect is less marked in Queensland, where summer temperatures generally result in high air conditional load.

[103] Firecone, The Impact of Locational Pricing on the contact market, November 2006. Snowy Hydro and Macquarie Generation supplementary submission to CMR, 22 December 2006.

The materiality of financial risks arising from constraints causing inter-regional price volatility depends on the effectiveness of the existing risk management instruments available to participants. The Directions Paper presented evidence and market surveys on the effectiveness of the SRA unit as a risk management instrument. Since then, we complemented this evidence base with a series of bilateral meetings with market participants. In these discussions, we found that market participants' "risk" appetite for inter-regional trading varied greatly and that they used a portfolio of instruments to manage risk rather than just relying on one mechanism. Some parties responded that their risk strategy was primarily driven by hedging an "n-1" plant contingency and that risks caused by congestion were more of a secondary concern. Other parties commented that the difficulty in forecasting the timing and impact of network constraints, especially with respect to planned outages, added to their risks.

Participants acknowledged the lack of firmness offered by the existing SRA products but were concerned about the potential risks of introducing major changes to the product, especially if such changes were made in isolation from initiatives to improve transmission performance.

We discuss the effectiveness of various risk management approaches used by participants in more detail in Appendix C.

B.4.3 Dynamic efficiency

Dynamic efficiency is the efficiency of market outcomes in promoting long-term investment decisions in generation capacity, transmission infrastructure, and/or load. We recognise that the dynamic efficiency aspect of congestion may have a significant effect on the NEM's overall economic efficiency. Furthermore, with significant investment planned in the energy sector over the next 5 to 15 years, there may well be considerable dynamic efficiency effects for the NEM.

This section discusses the implications of congestion for these longer-term decisions and outcomes. We considered two approaches for estimating these implications: data from NEMMCO's SOO-ANTS, and modelling conducted by IES.

B.4.3.1 NEMMCO's SOO-ANTS data

As noted in both the Directions Paper and the Draft Report, the ANTS provides an overview of the current state and potential future development of NTFPs[104] (being the portion of network used to transport significant amounts of electricity between load and generation centres). The ANTS also uses a market simulation model to develop a ten-year forecast of network congestion in order to identify the need for NTFP augmentation from a "market benefit" perspective.[105] In its 2007 ANTS, NEMMCO estimated the present value of the total market benefits of removing all network constraints at $1.6 billion over the next ten years. These markets benefits arise due to lower dispatch costs, deferral of capital expenditure, and reliability savings.[106] This value is lower than the $2.2 billion calculated in the 2006 ANTS. Reasons for this reduction include market benefits from projects considered committed or routine augmentations not included in the 2006 ANTS.[107]

NEMMCO notes, however, that it is not economically viable to capture all these market benefits, because the cost of the required transmission network augmentations would exceed this market benefit.[108] In addition, this analysis is unable to capture the magnitude of the likely future physical and financial trading risks associated with congestion, which limits its usefulness.

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[104] A NTFP is defined by NEMMCO as a flow path that joins major generator or load centres, is expected to experience significant congestion across the next ten years simulation period, and is capable of being modelling.

[105] Market benefit is a term used in the AER's Regulatory Test to describe the sum of consumer and producer surplus in the NEM. See AER, *Review of the Regulatory Test for Network Augmentations, Decision*, 11 August 2004, Version 2, note (5), p.9.

[106] NEMMCO, 2007 Statement of Opportunities, Melbourne, October 2007, pp.8-12.

[107] Ibid.

[108] Ibid.

B.4.3.2 IES's modelling of more granular congestion and transmission pricing arrangements

Background

Congestion has the potential to affect economic efficiency over time by influencing investment decisions by both generators and TNSPs. On this issue, the LATIN Group made a supplementary submission[109] which contained a modelling report undertaken by IES. The LATIN Group commissioned IES to model the potential future dynamic efficiency impacts of more granular congestion and transmission pricing arrangements.[110]

Using Queensland as a single region case study, IES estimated the extent of dynamic inefficiencies under the current Rules arising through the sub-optimal location and timing of generation and transmission investment. It compared the current regime of a single RRP for Queensland and "shallow" transmission connection charges for generators[111], to two alternative scenarios of: (a) introducing eleven nodal prices for Queensland via a full regime of constraint support pricing (see Appendix C, section C.5 for a discussion of CSPs); and (b) including a transmission congestion levy on new generators in addition to the congestion pricing regime included in scenario (a). The IES report found that both hypothetical scenarios would lead to a more efficient pattern of generation and transmission investment in Queensland, with scenario (b) yielding greater efficiencies than scenario (a), and with the scenario combining both options yielding greater efficiencies than the scenario relying solely on more granular congestion pricing.

Summary of IES Report and methodology

IES estimated the extent of dynamic inefficiencies caused by transmission investment and generation locational investment under the current regime, using a case study of the Queensland region for a 14-year period (2006/07 to 2020/21). The model compares the current pricing rule of a single RRP[112] for Queensland to two alternative cases:

- *Case 1.* Introducing eleven nodal prices for Queensland via a full regime of constraint support pricing.
- *Case 2.* Including a congestion levy on new generators in addition to the nodal pricing regime introduced under Case 1. The congestion levy estimated the cost

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[109] Southern Generators, Supplementary Submission to CMR, Modelling of future efficiency gains., 22 December 2006.

[110] Intelligent Energy Systems (IES), Modelling of Transmission Pricing and Congestion Management Regimes, Report, 22 December 2006.

[111] "Shallow" connection charges refer to the immediate and direct costs of generators connecting to the network and excludes any downstream network augmentation costs.

[112] Based on price at the South Pine node.

of transmission augmentation needed to relieve any congestion caused by each new generator location decision, in line with a causer-pays principle.

Scenario	Settlements	Transmission costs charged for new generation capacity
Base Case	Regional	No
Case 1	Nodal	No
Case 2	Nodal	Yes

Each case was modelled using a network model that included all material intra-regional constraints. The same physical network and constraints were used for all cases until the point in either Case 1 or Case 2 when modelling led to a change in network investment.[113]

The modelling was not a least-cost optimisation of both transmission and generation. It was an iterated two-staged approach which sought to represent a competitive market expansion plan. IES noted that this approach was designed to represent least-cost decision-making by each new generator and resulted in the difference in outcomes between cases being driven by the different pricing signals to generators.

The first stage in the modelling is to calculate a market-based automated generator entry. This new entry model is an iterative process of ranking the most economical plant each year based upon a comparison of each potential generator's SRMC to the average relevant nodal price. This assesses whether the spot market premium is sufficient to cover the generator's fixed costs.

The generator new entry assessment is only tested in the first year of the new investment, and hence there is net present value (NPV) assessment over the life of the generating plant. This means that a new generator enters the market if the relevant nodal price results in it making sufficient revenue to cover both variable and fixed costs in that year. IES considered that when load is increasing, it is a reasonable approximation to assume that if the plant is economic in the first year then it should be economic over its life.

The input list of potential new generators included known planned projects and generic new entrants spread across the network. There was no detailed verification as to the suitability of the location of the generic new generation projects.

After the new entry generation has been determined, the transmission response is calculated either against the reliability criteria or a market benefit assessment. The market benefit assessment gauges whether there is a large enough difference in the nodal prices to reflect high congestion costs to justify the expenditure.

[113] The modelling incorporates committed network upgrades, new generation plant and plant upgrades as per the 2006 SOO-ANTS and the TNSPs regional 2006 APRs. Demand growth for each of the 11 Queensland nodes was modelled using published energy and demand projection from the Powerlink 2006 APR. Generators' SRMC are the same for all cases and were based on the ACIL-Tasman cost estimates used by NEMMCO for the 2006 SOO-ANTS. Only system normal conditions have been modelled.

Like the generator new entry modelling, the transmission response is modelled as an annual iterative process. However, the modelling uses Powerlink's 2006 Annual Planning Review[114] forecasts of transmission expenditure for all three cases for the first ten years. This means that only in the last five years was it necessary for IES to determine the optimal transmission response to new generation entry.

IES thought that this approach was similar to how the current market operates, with TNSPs making investment decisions in response to committed generation projects and reliability criteria for loads.

Generators bids are determined in a manner that attempts to maximise profits given contract revenues and the applicable spot price (i.e. either the RRN price or the nodal price). The allocation of contracts to generators' portfolios is consistent across all cases, ensuring that contract allocation does not bias the results.[115]

The study estimated that by introducing nodal pricing to the Queensland region through a comprehensive constraint support pricing (CSP) regime, there would be an overall net NPV benefit of $194.65 million in efficiency savings. Although the results for Case 1 showed an increase in the overall dispatch costs caused by increased generation from a relatively more expensive plant, this was more than offset by significant reductions in transmission and generation capital costs. The modelling found that nodal pricing in Queensland would result in generation replacing transmission upgrades. IES estimated that the benefit would increase to $222 million (NPV) with the addition of congestion levies on new generation in Queensland.

Table B.4 Results from IES modelling on the comparison of total savings of introducing locational pricing and congestion levies, Queensland region ($m NPV for 2006/07 to 2020-21)

	Net Present Value ($m)			
Case	Dispatch cost savings	Generator capital cost savings	Transmission expenditure savings	Total savings
1 Locational pricing	-58.06	130.8	121.91	**194.5**
2 Locational pricing with congestion levy	-365.52	464.06	123.98	**222.5**

The introduction of a congestion levy in Case 2 dramatically changes the dispatch costs and the savings in generation capital costs compared to Case 1 results. There is

114 Powerlink, Annual Planning Report, 2006.

115 The bidding is based upon the regional/nodal price clearing the market. Effectively each generator has one shot to respond to the pre-dispatch price and price sensitivities. The generator's response is based upon profit maximising behaviour with generators determining their optimal bid based on a price volume trade off considering their contract level. IES considered this to reasonably represent actual bidding behaviour.

a substantial increase in the dispatch costs which is, however, more than offset by the reduction in generator capital costs.

The congestion levy acts as a barrier to entry, making remote generation more expensive and encouraging generation closer to the load. Under Case 2, remote generation (which is generally coal) is heavily discouraged. This process results in less total plant capacity in Case 2 than Case 1. Also Case 2 has a slightly higher unserved energy amount (although still at a level well below the reliability standard). Effectively, under Case 2 the system is run a bit tighter, i.e. there is a closer match of supply and demand than in Case 1.

There is variation in the fuel type and location of new entry generation between the three cases. The Base Case estimates that there will be an extra 2 500 MW built in Queensland in addition to the planned projects. Of the 2 500 MW of extra generic investment, 1 500 MW is coal-fired plant located in the South West. The remaining new plant is gas-fired located in Gladstone and Moreton, and is primarily required to meet shoulder and peak requirements.

Compared to the Base Case, an extra 500 MW is estimated to enter the market in Case 1. Also there is a different generation mix, with more gas-fired and less coal plant; and location is different, with more new entry generation in Moreton South, Gold Coast (Tweed) and Wide Bay.

The congestion levy in Case 2 results in significantly less new generation entry. IES estimated that 900 MW less generic new entry will occur. As noted above, the congestion levy results in remote coal-fired generation being replaced by gas-fired generation closer to load.

IES applied a discount rate of 9 per cent for its calculations. We calculated that adjusting the discount rate by one percentage results in approximately a $20 million adjustment to the NPV gains either way (i.e. a 10 per cent discount rate decreases the gains by $20 million and an 8 per cent rate would increase the benefit by $20 million). For the modelling, IES did not use terminal values but instead applied an annual equivalent cost approach which accounts for terminal values of any new assets by spreading it over the life of an asset in the annual capital cost.

In should also be noted that in 2004, IES did a similar modelling study for the ACCC which formed part of its submission to the Ministerial Council on Energy (MCE) on the CRA report on NEM regional structure review.[116] That report considered the magnitude and materiality of the costs and benefits of implementing either a full nodal pricing regime for generators and consumers, or nodal pricing for generation only. IES concluded that a nodal pricing regime would be likely to induce different generator behaviour and that this may have material benefits in terms of the NEM dispatch costs—mainly through fuel costs. IES also concluded that a change from regional pricing to nodal pricing would yield as much benefit to the market as the amount of transmission investment that would be required to eliminate half the dispatch costs due to intra-regional transmission constraints in Queensland.

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[116] IES, Regional Boundaries and Nodal Pricing, an analysis of the potential impact of nodal pricing and market efficiency, Report to ACCC, 12 December 2004.

Review of IES modelling approach

The IES report presents an important and useful attempt at quantifying the long-term market benefits under various pricing regimes. However, the modelling was restricted in its breadth, particularly because of time constraints. Therefore, it is limited in terms of how much it can inform this Review. We discuss these limitations below.

Unable to consider the risk implications of introducing nodal pricing

Nodal pricing will create a different set of risks for generators, compared with those they face in the current regional structure, and this will have implications for the trading and contract position of market participants. IES's modelling and assessment did not factor in the cost of this increased risk, particularly in the absence of any risk management instruments (e.g. constraint support contracts).

The modelling is therefore unable to measure the full effect and implications of moving from a regional structure to a nodal prices structure. We understand the model did not do so because IES considered that this would have required a subjective judgement on quantifying the risks under the different pricing rules. While noting the difficulties of doing this, the modelling results probably overestimate the benefits of a move to nodal pricing by not incorporating the likely costs associated with the increase in basis risk for participants.

Model limited to Queensland, with simplified representation of other NEM regions

To manage the size and complexity of the modelling exercise, with the exception of flows on QNI the NEM was modelled in this analysis on a regional basis with no intra-regional constraints. Consequently the model was unable to account for interactions between Queensland and the other regions. For example, it did not account for the possibility that a higher Queensland price might lead to a higher NSW price. That being said, IES noted that under all three cases the South-West Queensland nodal prices were fairly equal. As this is the price that can impact on the NSW price, IES did not consider that the impact on NSW would differ significantly under the different Queensland scenarios.

While that may be the case for NSW, under a nodal model there will be many more of these possible interactions, given the increase in the number of pricing nodes. By not accounting for the consequences of these possible interactions, even on a regional basis, the modelling possibly underestimates the implications from moving away from the current regional pricing structure.

Limited time prevented sensitivity analysis on results

IES informed us that it was unable to undertake sensitivity analysis due to time limitations. Sensitivity analysis would help to improve the quantification of costs. It would provide information on how much key assumptions drive the results.

One example is the generator costs estimates which are based on ACIL-Tasman long-term estimates. These figures do not reflect the current short-term costs facing generators; for example, higher costs for gas turbines caused by high world demand, or higher construction costs caused by shortages of skilled labour.

Sensitivity analysis would put into perspective the possible range of benefits found by IES and would provide information on what modelling assumptions were most influential in driving the results. Without it, it is difficult to determine what weight to place on the results and how likely they are to change, and in what direction, should an assumption change.

Verification of whether the location of the additional generation was plausible

As noted above, the modelling assumes no constraints on fuel availability, water or other factors which affect generation location. Both Powerlink and Stanwell in their submissions to us argued that this results in unrealistic new entry generation scenarios.

Powerlink argued that this assumption leads to the projection of significant amounts of new generation in the South East Queensland/Brisbane load centre, where there are constraints on fuel availability and cost, water and environmental acceptability. It considered that these real-world constraints would cause most new generation to locate at more favourable locations, which would ultimately mean more transmission investment. Stanwell considered that gas-fired generation will become the dominant fuel choice of the new entry generators in Queensland, irrespective of the pricing regime.

In response to this, IES noted that its assumptions on locations were the assumptions calculated by ACIL-Tasman and used by NEMMCO for its reliability modelling for the SOO, and therefore considered the new generation locations to be plausible.

Generic transmission costs estimates used for congestion levies

IES used a very simple transmission pricing model that assumes transmission costs are based on distance to load. It has noted that the transmission costs estimates used to determine the congestion levies for new generation were simplistic and that better cost estimates from the TNSPs would help to qualify the results. It also recognised that it is difficult to model individual causer-pay congestion levies for new generators because each transmission augmentation will be highly dependent upon the exact circumstances. IES did inform us that better estimates of congestion levy would improve the model.

Transaction costs and implementation costs of introducing new pricing regimes not included

There will be significant transaction and implementation costs of changing the current regional pricing structure to a nodal pricing system, for example IT and administrative costs. None of these costs was included in the modelling, hence we consider that IES's results may overstate the benefits of introducing different pricing structures.

IES did attempt to quantify the costs associated with implementing nodal pricing, in previous work done for the ACCC.[117] In its report on that work, IES estimated that implementing generator nodal pricing would result in approximately $7.2 million to $14.9 million in IT capital costs and ongoing operational costs of up to $2.4 million (2004 prices).

Conclusion

The IES work is an important and useful attempt at quantifying long-term market benefits under various pricing regimes. However, the assumptions used limit how much the analysis can inform this Review.

The assumptions on risk implications, investment decisions and implementation costs are the main limiting factors. The modelling did not factor in the risk implications and implementation costs of introducing greater locational pricing. It also did not include a review of whether the location of additional generation was plausible.

These limitations are understandable given the time constraints IES faced in undertaking such a substantial modelling exercise. They do mean, however, that the cost estimates of the current regional pricing regime are probably overestimated, because they do not account for factors that are potentially quite influential, such as the risk implications for a nodally-priced regime. The IES report provides a useful starting point for assessing the costs of congestion and the possible benefits from pricing it. However, the magnitude of these benefits is unlikely to be as substantial as the report suggests. The report demonstrates how difficult it is to quantify dynamic efficient benefits.

[117] Ibid.

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