Australian Energy Market Commission

Congestion Management Review

Final Report

June 2008

Signed: ....

John Tamblyn
Chairman
For and on behalf of
Australian Energy Market Commission

Commissioners
Tamblyn
Carver
Woodward

Inquiries

The Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

Citation

AEMC 2006, *Final Report*, Congestion Management Review, June 2008, Sydney

About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy, established the Australian Energy Market Commission (AEMC) in July 2005 to be the Rule maker for national energy markets. The AEMC is currently responsible for Rules and policy advice covering the National Electricity Market. It is a statutory authority. Our key responsibilities are to consider Rule change proposals, conduct energy market reviews and provide policy advice to the Ministerial Council as requested, or on AEMC initiative.

Foreword

The Australian Energy Market Commission is pleased to submit its Final Report on the Congestion Management Review for consideration by the Ministerial Council for Energy (MCE).

We were asked by the MCE to undertake this Review in October 2005, with a view to identifying ways of improving the ability of market participants to manage risks resulting from congestion on the transmission networks. We have consulted widely with stakeholders through the course of this Review, and analysed a wide range of evidence and policy options.

The Final Report, together with the work we will shortly complete for the MCE on national transmission planning arrangements, brings to a close a significant programme of reform to wholesale market and transmission Rules for the National Electricity Market (NEM) over the past three years. A result is a Congestion Management Regime which promotes efficiency, and is proportionate to the materiality of congestion in the NEM historically.

The Final Report also foreshadows a new phase of review and potential reform, as market participants and policy makers seek to understand the implications of policy responses to climate change for the economics and future performance of the NEM. Any path to reduce Australia's CO_2 emissions will necessarily involve the NEM and other energy markets to a significant degree. The foundation of the NEM is a regulatory framework based on effective competition and sound regulation of monopoly businesses, which promotes safe, secure and efficient supplies of electricity to consumers. It is important that we continue to scrutinise the ability of our market Rules to integrate new policy instruments, and the changes in market behaviour that such policies will elicit, to continue to promote these positive outcomes for consumers. I would hope that the Australian Energy Market Commission can make a valuable contribution to this process.

John Tamblyn

Chairman

Contents

Executive summary

This is the Australian Energy Market Commission's (AEMC) Final Report on its Congestion Management Review (the Review). The Final Report:

- describes the framework (the "Congestion Management Regime") for understanding and managing congestion in the National Electricity Market (NEM);.
- recommends to the Ministerial Council for Energy (MCE) specific changes to the National Electricity Rules that will improve the management of transmission congestion in the NEM. These recommendations build on a range of congestion management reforms already being implemented; and
- looks beyond the immediate MCE Terms of Reference for the Review and sets out key issues and drivers for change likely to impact on the Congestion Management Regime in the future.

The Terms of Reference for this Review required that we develop arrangements to improve the management of physical and financial trading risks associated with material transmission congestion. We were also tasked with developing a location-specific interim constraint management mechanism for managing material constraint issues until such time as they are addressed through investment or region boundary change. Furthermore, the MCE stipulated that a nodal approach to pricing is not appropriate at this stage of market development.

Context

This Report is one part of a wider and ongoing suite of reforms to the regulatory framework for the wholesale market and transmission. This wider suite of reforms impacts both the emergence and management of transmission congestion. It includes:

- regional boundary reform to the Snowy region to address the one significant, enduring and material point of congestion in the NEM;
- amendments to the Rules to introduce a new process for managing region boundary changes in the future;
- amendments to the Rules to establish a new Last Resort Planning Power (LRPP) to address the risk to the market of significant planning failure by Transmission Network Service Providers (TNSPs); and
- a new framework for the economic regulation of transmission (amendments to Chapter 6A of the Rules).

The current phase of the reform process will conclude with our review of national transmission planning arrangements, which later this year will deliver recommendations to the MCE on: an implementation plan to establish a National Transmission Planner; amendments to the Regulatory Test; and the establishment of a framework for establishing greater consistency across the NEM in transmission planning standards for reliability.

Recommended Rule changes

In response to the Terms of Reference, we are recommending to the MCE four specific Rule changes to improve the arrangements for managing financial and physical trading risks associated with material network congestion. The changes focus on enhancing the quality of information available to market participants to help them understand the risks associated with congestion, and on improving the effectiveness of risk management instruments. The changes, if implemented, will:

- formalise in the Rules NEMMCO's use of fully co-optimised network constraints for the purposes of dispatching generation and Market Network Service Providers;
- amend the Rules governing the funding of negative settlement residues so as to reduce uncertainty for holders of Inter-Regional Settlement Residue (IRSR) units;
- establish a new Congestion Information Resource (CIR), to be published by NEMMCO, which will consolidate and enhance existing sources of information relevant to the understanding and management of congestion risk; and
- clarify and strengthen the Rules governing the rights of generators who fund transmission augmentations as a means of managing congestion risk, so that in the future connecting parties make a contribution to those funded investments from which they will benefit.

Congestion and wholesale market pricing

In the NEM, the market and system operator NEMMCO dispatches the market every five minutes with the objective of minimising the cost of dispatch based on bids and offers from generators and larger load customers.[a] A generator therefore faces a risk that it might not be dispatched for its desired output. This is physical (or "dispatch") risk. A generator also faces financial (or "basis") risk to the extent that it enters into contracts referenced to prices in other regions. In other market designs generators are allocated, or can purchase, a transmission access right which affords protection against volume risk. In the NEM, a generator's "right" to use the transmission network depends on whether it is dispatched by NEMMCO or not. This is termed an "open access" transmission regime.

A regionally-priced market design has two main congestion-related policy challenges which can potentially result in decentralised decision making by market participants, which can lead to economically inefficient outcomes. First, congestion can create incentives for generators to submit bids that do not reflect costs; this is done in order to secure or avoid dispatch, i.e. to manage dispatch risk (the "dis-orderly bidding problem"). If the market is dispatched using bids that do not reflect costs, then the

[a] Dispatch is also subject to the constraint of managing the security and reliability of the power system.

dispatch may be more costly (in terms of underlying resource costs) than it needs to be.

Second, congestion, and the way it is priced in the market, can influence the locational decisions of investors (the "location decision problem"). To the extent that congestion is priced in the market, this can provide signals for the optimal timing and location of generation, network and large customer investments.

The incentives for generators to submit bids that do not reflect costs as a means of managing volume risk can be addressed by linking more closely the price a generator receives in settlement to the value of its bid. Calculating prices individually for each point (node) of the network is one means of doing this. Another method, which the MCE directed us to review, is a location-specific interim constraint management mechanism. There are many different designs for such a mechanism, but the basic framework involves (a) introducing nodal prices for generators in a designated geographical area, and (b) allocating rights to generators in the area, to be settled at the RRP. If a generator is dispatched for a volume greater than its allocated rights, then it is paid its nodal price for the surplus generation. This encourages a generator to submit bids that more accurately reflect underlying resource costs.

While in a location-specific and time-limited manner a constraint management mechanism does address the "dis-orderly bidding problem", its presence is unlikely to be the determining factor in investment decisions, and therefore it will not resolve the "location decision problem". A location-specific interim constraint management mechanism is inherently uncertain and short-term. Decisions on long-term investment—for example, whether to finance a project and, if so, what project and at what cost—will instead be dominated by the other, more enduring price and non-price signals that already exist in the market. These include price differences between regions, the prospect of changes to pricing regions, transmission losses, volume risk, connection and other negotiated transmission costs, proximity and access to the electricity grid, and proximity to transport infrastructure for generation fuel sources. Importantly, it is how these signals combine, rather than the form or strength of a particular individual signal, that matters when assessing their impact on the efficiency of outcomes for consumers.

In conclusion, we are not persuaded that a location-specific interim constraint management mechanism will promote the National Electricity Objective at this stage, given the prevailing patterns and economic materiality of congestion. Analytical work by the Australian Energy Regulator (AER) and by us suggests that productive inefficiencies from dis-orderly bidding have been relatively minor to date. In addition, empirical research from NEMMCO shows that congestion has tended to be transitory and influenced significantly by network outages, hence it would be difficult to target exactly where localised pricing interventions should be applied.

Furthermore, the introduction of a location-specific interim constraint management mechanism would add a layer of complexity to the market design and would require the resolution of significant design issues. It would introduce more settlement prices. The entitlement for a NEM generator to be settled at the regional price for its dispatched output would be removed, and replaced with another form of entitlement. The entitlement is important because it represents a mechanism for managing price risk. In some proposed designs this alternative entitlement would be allocated using an administrative rule, while in others rights would be defined explicitly and released for sale through an auction. The introduction of firm transmission rights for generation would involve fundamentally changing the NEM's design and would raise complex policy questions such as whether such rights should be grandfathered, auctioned or allocated on some other basis. Given the evidence to date does not show that transmission congestion has been a material problem, and given the complexities associated with designing a location-specific interim constraint management mechanism we are not persuaded that such a mechanism represents a net improvement in market efficiency at this time.

Future challenges

During the course of this Review there has been an increasing focus among stakeholders on the "location decision problem". This has revealed itself in proposals for more fundamental change to the Congestion Management Regime, including NEM-wide changes to abolish or amend the entitlement for dispatched volumes to be settled at the regional price and to introduce alternative mechanisms for managing price risk. This shift of focus reflects the need for new investment in the NEM, as well as the uncertainty over the nature of such investment in the context of climate change and policy responses to it.

The impact on the NEM of government policy initiatives in response to climate change (including the promotion of renewable energy technologies) will be profound. There are likely to be: significant amounts of new generation in remote parts of the network; closure of existing fossil fuel generation capacity; large shifts in the patterns of electrical flows across transmission and distribution networks; and new challenges for system operation and security of supply resulting from significant volumes of intermittent generation, such as wind turbines or small-scale embedded or micro generation. The pattern of these changes will be strongly influenced by policy settings, such as the details of a national emissions trading scheme, which are yet to be resolved.

These changes are likely to "stress test" the NEM's regulatory framework including the Congestion Management Regime. While further reforms to the Regime should be proportionate to the problem and have a robust analytical basis, we should be aware that even a proportionate response might involve significant reform to the regulatory framework. The changes to the underlying economics of the NEM resulting from climate change policy, and the consequent impacts on the behaviour of market participants and on what is required of the NEM's transmission networks, are potentially very large and may, among other consequences, result in the emergence of material transmission congestion.

If analysis were to indicate that material transmission congestion is likely to emerge as a consequence of changes to the underlying economics of the NEM, it is likely that there will be numerous options for reform that warrant consideration. For example, if new and stable points of material congestion emerge, perhaps as a result of timing differences between generator and network investment responses, it might be appropriate to re-evaluate location-specific interim constraint management mechanisms as a transitional device. A more extensive reform option would be the introduction of Generator Nodal Pricing (GNP) on a NEM-wide basis. GNP would solve the dis-orderly bidding problem, and would be more effective at addressing the locational decision problem than would a localised, time-limited pricing intervention. However, it would represent a significant change to the NEM market design and would require a complete overhaul of the market architecture for managing price risk. As a companion piece to this Review we have undertaken initial but substantial analytical work on the potential application of GNP.[b]

The profound impact of policy responses to climate change on the underlying economics of the NEM suggests that it is timely to consider the case for more fundamental change. It is important of course that any such review be comprehensive and integrated; the complexity of the interactions, and the consequent risk of unintended consequences, mean that partial approaches are unlikely to deliver optimal outcomes. The review should be based on empirical evidence and robust analysis, and informed by effective and inclusive consultation with stakeholders.

A comprehensive review would consider the need for modifications to the energy market design and regulatory framework to ensure that the impacts of climate change policies on the NEM can be accommodated efficiently and at least cost. Such a review would need to address issues including:

- the likely nature and extent of the impact of climate change policies on the structure, economics and performance of the NEM;

- the identification of any elements of the NEM regulatory framework that may require incremental or more fundamental change to accommodate the impacts of climate change policies; and

- the identification and assessment of feasible options for change to the energy market design and regulatory framework to facilitate the integration of climate change policies with the continued efficient operation and performance of the NEM.

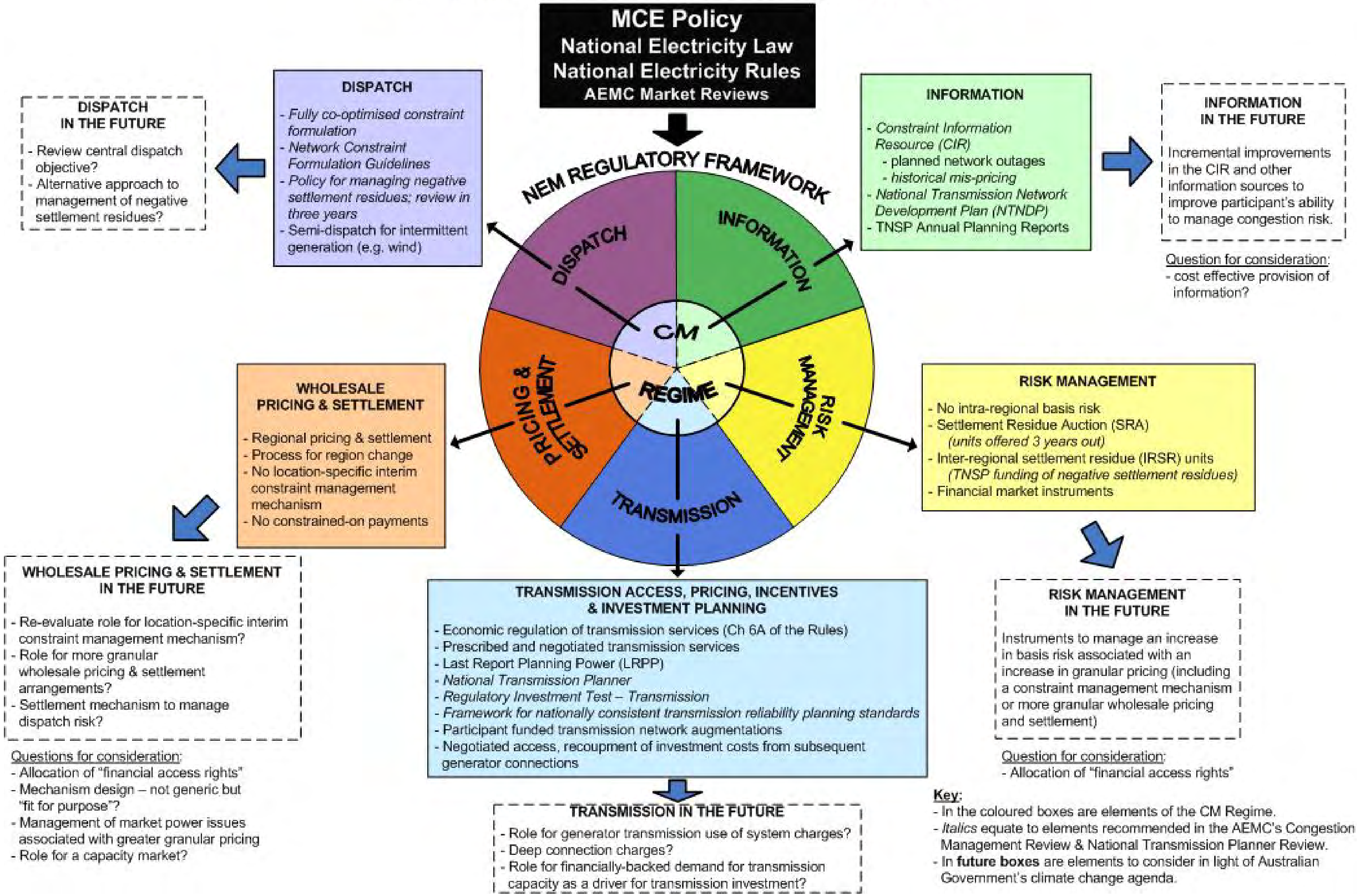
The diagram below represents what the Congestion Management Regime will look like in the NEM—if the recommendations in this Final Report as well as recommendations from related work in the National Transmission Planner review are implemented. The diagram also identifies areas where it will be beneficial in the future to consider how climate change policies may interact with and impact on the NEM's regulatory framework.

Building upon the congestion management reforms already being implemented, this Final Report together with its recommendations for incremental improvements to the Congestion Management Regime provide important direction on the nature and scope of the priority areas for future review and reform in the context of climate change policies.

---

[b] We commissioned Frontier Economics to undertake a review on the potential application of GNP. We also had Professor Grant Read of EGR Consulting provide a peer review of the Frontier Economics report. These supplementary papers are available on our website: www.aemc.gov.au.

What does the Congestion Management Regime look like in Australia's National Electricity Market?



This page has been intentionally left blank

1 Overview

1.1 Introduction

This is the Australian Energy Market Commission's (AEMC) Final Report on its Congestion Management Review (the Review). The Final Report:

- describes the framework (the "Congestion Management Regime") for understanding and managing congestion in the National Electricity Market (NEM);
- recommends to the Ministerial Council for Energy (MCE) specific changes to the National Electricity Rules that will improve the management of transmission congestion in the NEM. These recommendations build on a range of congestion management reforms already being implemented; and
- looks beyond the immediate MCE Terms of Reference for the Review and sets out key issues and drivers for change likely to impact on the Congestion Management Regime in the future.

1.2 Context and scope of the Review

1.2.1 Terms of Reference

In October 2005, we were directed by the MCE to review congestion management in the NEM.[1] We were asked to identify the financial and physical risks associated with material congestion and to propose improved arrangements for managing these risks prior to their being addressed by investment or region boundary change.[2] Specifically, the Terms of Reference directed us to examine and report on:

- improved arrangements for managing financial and physical trading risks associated with material network congestion, with the objective of maximising net economic benefit to all those who produce, consume and transport electricity (clause 3.1); and
- the feasibility of a constraint management regime as a mechanism for managing occurrences of material congestion at a particular location until they are addressed by investment or a boundary change (clause 3.2).

In undertaking these tasks, the Terms of Reference required us to:

- take account of and articulate the relationships between a constraint management regime, constraint formulation, regional boundary change criteria and review

1 Under Part 4, Division 4 of the National Electricity Law (NEL).

2 Ministerial Council on Energy (MCE), Terms of Reference clause 3.1, Congestion Management Review (CMR), 5 October 2005, p.4.

triggers, Annual National Transmission Statement (ANTS) flowpaths, the Last Resort Planning Power (LRPP), the Regulatory Test, and Transmission Network Service Provider (TNSP) incentive arrangements (clause 3.2); and

- have regard to previous work undertaken by Charles River and Associates (CRA) and the results of the limited Tumut Constraint Support Contract/Constraint Support Pricing (CSC/CSP) trial in consultation with the National Electricity Market Management Company (NEMMCO) (clause 3.3).

The Terms of Reference are provided in Appendix F.

1.2.2 Interpreting the Terms of Reference

We interpreted the MCE's Terms of Reference for this Review to mean the following:

- We should assess in parallel the economic costs of congestion and the options for improving market arrangements for congestion management, to ensure that our final recommendations are proportionate responses to the evidence and show due regard for the benefits of maintaining stability in the regulatory framework.

- Since we have a statutory duty to promote economic efficiency in the NEM, we should consider only those congestion management options that offer *net* benefits to market stakeholders.

- We should investigate the potential for location-specific interim constraint management regimes to manage location-specific material congestion until such time as it is addressed permanently by investment or region change.

- In assessing options to assist market participants, we should consider not only arrangements that could help them better manage the trading risks of congestion directly but also arrangements that could reduce the prevailing level of congestion and thereby reduce the trading risks of congestion indirectly.

1.2.3 The statutory objective

When we undertake any of our functions, including this Review, we are required under the National Electricity Law (NEL) to pursue the National Electricity Objective (NEO). The NEO is to:

> "promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—(a) price, quality, safety, reliability and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system."[3]

[3] Section 7, National Electricity Law (NEL).

An important consideration in light of the NEO is to assess any proposed change in terms of how it may affect the market's economic efficiency. We define economic efficiency as having three elements:

- *productive efficiency*—this means the electricity system should be operated on a "least cost" basis given the existing and likely network and other infrastructure.; for example, generators should be dispatched in a manner that minimises the total system costs of meeting consumers' demands;

- *allocative efficiency*—this means electricity production and consumption decisions should be based on prices that reflect the opportunity cost of the available resources; and

- *dynamic efficiency*—this means that ongoing productive and allocative efficiency should be maximised over time; dynamic efficiency is commonly linked to the promotion of efficient longer-term investment decisions.

Our recommendations are also consistent with good regulatory practice principles. This includes seeking stability and predictability in the regulatory framework by having regard to the need, where practicable, to:

- minimise operational intervention in the market—interventions in competitive markets should be limited to addressing market failures;[4]

- promote changes that are likely to be robust over the longer term—market Rules should be stable, or changes to them predictable, so that participants and investors can plan and make informed short- and long-term decisions; and

- promote transparency in market operations—if the market requires interventions, they should be transparent and consistently applied.

In addition, we only consider options that are consistent with the continued quality, security and reliability of the national electricity system.

1.2.4 The consultation process

We have developed the recommendations in this Final Report through detailed analytical work and extensive consultation with stakeholders. Our conclusions and recommendations are based on data and analysis provided by NEMMCO, the Australian Energy Regulator (AER) and our own consultants.[5] We also sought specific comments from stakeholders at different stages of the Review on the various options and approaches under consideration.

At each stage of the Review we published papers to keep stakeholders informed of progress and to seek their comment:

---

4 A market failure does not always require a regulatory intervention, however.

5 We discuss these in detail in Appendix B.

1. an Issues Paper (March 2006) that outlined our understanding of the Terms of Reference and the impacts of congestion on the market;

2. a Statement of Approach (June 2006) that set out the process we intended to take in progressing the Review and related issues;

3. a revised Statement of Approach (December 2006) that updated the process for progressing the Review and related issues;

4. a Directions Paper (March 2007) that presented some preliminary findings on materiality and a discussion of the options we considered worth closer examination;

5. a Draft Report (September 2007) that presented our proposed recommendations for improving congestion management arrangements in the NEM; and

6. Exposure Drafts (March 2008 and May 2008) that presented legal drafting to implement the changes to the Rules that we recommended in the Draft Report.

Throughout the Review process we also liaised directly with stakeholders through bilateral meetings, workshops and industry forums.

1.2.5 Related AEMC work

Since the Terms of Reference for the Review were issued, a number of reforms have been made to the regulatory framework for the wholesale market and transmission—reforms that affect both the emergence and management of transmission congestion. Reforms implemented from late 2005 to 2008 include:

- region boundary reform to the Snowy region to address the one significant, enduring and material point of congestion in the NEM;

- amendments to the Rules to introduce a new process for managing region boundary changes in the future;

- amendments to the Rules to establish a LRPP to address the risk to the market of significant planning failure by TNSPs; and

- a new framework for the economic regulation of transmission (Chapter 6A of the Rules).

Further reforms are also in progress. Our review of national transmission planning arrangements will later this year deliver recommendations to the MCE on: an implementation plant to establish a National Transmission Planner (NTP); amendments to the Regulatory Test; and the establishment of a framework for establishing greater consistency across the NEM in transmission planning standards for reliability.

This Review should be understood not in isolation but as part of a wider package of reforms. Furthermore, in developing our recommendations we have carefully taken into account how this Review and the other reforms interact, to ensure that the measures we are proposing here are consistent with, and complementary to, those reforms.

1.3 Future developments

The timing of this Review has coincided with an increasing emphasis on, and clarity around, policy responses to climate change. This is illustrated by, among other things, the commissioning of the Garnaut Review by the Commonwealth, State and Territory Governments. The stated purpose of the Garnaut Review is to examine the impacts of climate change on the Australian economy and to recommend medium- to long-term policies and policy frameworks to improve the prospects for sustainable prosperity. The Final Report of the Garnaut Review is due to be published on 30 September 2008.

Policy responses to climate change, such as an Emissions Trading Scheme (ETS) and the Mandatory Renewable Energy Target (MRET)[6], will have considerable impact on the NEM, particularly on the economics of the market, including the relative competitiveness of different generators and demand-side alternatives. In turn, this will influence the dispatch process, the demand for new connections, and the patterns of electrical flows across transmission and distribution networks.

Climate change policies are emerging, coincidentally, at a time when the NEM is experiencing a tightening supply-demand balance. This compounds pressure for new investment in the market. It may also have implications for the reliability of supply as well as the security of the power system.

These developments will "stress-test" the existing Rules and regulatory framework for the NEM, including the management of congestion. We comment on some of these issues in the chapter 4 of this Final Report.

1.4 Structure of this Final Report

There are three other chapters in the Main Body of this Final Report:

- *Chapter 2* explains what congestion is, who it affects, and why it needs to be managed. It describes the purpose and characteristics of a Congestion Management Regime (CM Regime). It also presents the evidence on the prevalence and economic materiality of congestion in the NEM over the past five years.
- *Chapter 3* sets out the component parts of the CM Regime for the NEM and describes how we recommend improving it to support more efficient outcomes.
- *Chapter 4* examines how the CM Regime may need to evolve in the future in order to accommodate policy responses to climate change and a tightening supply and demand balance.

6 The MRET target is 45 000 GWh of output from renewable generators by 2020.

Appendices provide background information and/or more detail on congestion and its context:

- *Appendix A – Introduction to congestion*
- *Appendix B – Prevalence and materiality of congestion*
- *Appendix C – Assessment of Congestion Management Regime elements*
- *Appendix D – Outlook for future trends in congestion*
- *Appendix E – Additional material*, which includes:
  - types of constraints
  - review of CRA work on constraint management
  - Network Support and Control Services
  - Positive Flow Clamping.
- *Appendix F – MCE Terms of Reference for this Review*
- *Appendix G – Draft Rules*[7]
- *Appendix H – Glossary*

---

7 In the Review's Terms of Reference, the MCE requested that in addition to making recommendations we should develop draft Rule changes to implement the recommendations. These draft Rule changes are presented in Appendix G. They articulate provisions to implement our recommendations for network constraint formulation, the establishment of a Congestion Information Resource, the recovery of negative settlement residues, and contributions to transmission augmentation.

2 Congestion in the NEM: Concepts and evidence

2.1 What is congestion?

Electricity is transported from suppliers (generators) to consumers (retailers and large customers) along a transmission network. "Congestion" is what happens when there is a bottleneck somewhere on this network. That is, whenever a particular element on the network (e.g. a line or transformer) reaches its limit and cannot carry any more electricity than it is carrying already, it is "congested". The flow of power across the network means that when a limit is reached on one part of the network, adjustments have to be made in generation and consumption across the network to ensure that the limit is not exceeded.[8]

In technical terms, congestion places network constraints on dispatch. It interferes with the market's dispatch objective of meeting demand at the lowest possible cost. (In the absence of congestion, electricity to meet demand is supplied by the lowest-cost generators;[9] when congestion arises this may not be feasible, so higher-cost generators may have to be dispatched instead.) This introduces risks for the market, which consequently affects bidding[10], dispatch, pricing, contracts, and risk management, as well as long-term investment decisions.

2.2 Who is affected by congestion and how?

Congestion affects everyone in the market. It affects generators by increasing their exposure to financial and physical risks. It affects retailers by increasing their exposure to financial risk. It affects investors by creating a greater level of uncertainty about locational decisions (i.e. where to invest in transmission and/or generation). It affects NEMMCO (the system and market operator) by increasing the possibility of system security and supply reliability problems. In addition, by increasing the price of electricity, it also affects both wholesale and retail customers.

In response to the risks caused by congestion, market participants engage in strategies and activities to manage those risks. This leads to behaviours—such as "dis-orderly bidding" by generators—that reduce the economic efficiency of the NEM in both the short and long terms.

2.2.1 How congestion influences the behaviour of participants

Congestion can introduce two kinds of short-term risk that generators have to manage:

---

8 See Appendix A for an "Introduction to congestion in the NEM".

9 This assumes that generator bids reflect costs.

10 In the NEM, the term generator "bid" has the same meaning as generator "offer", and "rebidding" has the same meaning as "re-offering".

- dispatch risk (also known as physical or volume risk); and
- basis risk (also known as financial or price risk).

The magnitude of these risks depends on the pricing and settlement arrangements in the market and how explicitly those arrangements reflect congestion.[11]

Dispatch risk

A generator faces dispatch risk when the Regional Reference Price (RRP)—i.e. the *actual* (or settlement) price it is paid for supply—diverges from its local (or nodal) price—i.e. the *hypothetical* price reflecting its local demand and supply conditions. The RRP is set at the cost of supplying an additional megawatt of electricity at the regional reference node (RRN). The RRN is a specified point in a region; it is normally close to the region's largest demand centre.

Dispatch in the NEM is based on a comparison between a generator's offer price and its local price. Dispatch assumes that generator offer prices are cost reflective.

When there is no congestion, local prices across the network are the same as the RRP. Congestion changes that. When congestion arises between a generator's location and the RRN, the generator's local price and the RRP can diverge. This "mis-pricing" creates dispatch risk for the generator, exposing it to the possibility of:

- being dispatched and settled at a price that does not meet its incremental costs (i.e. it is negatively mis-priced or "constrained-on"); or
- missing out on being dispatched even though its offer price is below the RRP (i.e. it is positively mis-priced or "constrained-off").

In order to manage dispatch risk, generators change their bidding behaviour such that they no longer bid in a cost-reflective way. That is, dispatch risk creates an incentive for generators to engage in "dis-orderly bidding". At the extremes, generators may bid in at the market floor price (-$1 000/MWh) to avoid being constrained-off, or at the market ceiling price ($10 000/MWh) to avoid being constrained-on.

Generators' bidding practices in turn affect dispatch. Mis-pricing leads to dis-orderly bidding, which can result in the dispatch of higher-cost generators over lower-cost generators. To the extent that generators' congestion-influenced bids distort what would otherwise be efficient dispatch outcomes, mis-pricing introduces productive inefficiency.

Basis risk

Basis risk arises when the settlement price a participant pays (or receives) diverges from the *contract* price the participant agreed to.

---

[11] Why this is a consequence of a regionally-priced market is explained in Appendix C.

Currently, participants do not face basis risk when trading within a region. This is because generators receive (and loads pay) the same price for producing and consuming electricity within a region. This is the case irrespective of the level of congestion within that region. This means both generators and customers have a "perfect" hedge built into the settlement arrangements for any contracts between two participants in the same region.

Participants do face basis risk when trading between regions, however. When congestion arises between regions, the price between those regions diverges. A participant who contracts between these regions needs to manage the price difference to the extent that it has contracted at one region's RRP but is settled at the other region's RRP.

Participants use financial instruments to help manage this inter-regional basis risk. Their willingness to contract between regions depends on: (a) the ability to obtain risk management instruments; and (b) the usefulness of those instruments in managing the risk. To the extent that participants can access instruments, and that these instruments provide an acceptable hedge cover, participants may choose to trade inter-regionally. If participants cannot obtain sufficient hedge cover, they may choose not to contract across regions. This can reduce the potential contracting pool at load centres, which limits the extent of competition in the contract market.

2.2.2 How congestion influences the behaviour of investors

In the long run, mis-pricing may distort investment decisions for both supply and load. This includes decisions on technology, location and timing. For example, a new entrant may apply a higher discount rate if the level of dis-orderly bidding in an area makes it difficult for that new entrant to manage its own dispatch risk. If the new entrant is more efficient than the existing generators, this could compromise dynamic efficiency.

In the longer term, this can weaken economic signals that support efficient locational investment decisions by generators and large industrial and commercial users (the "location decision problem").

2.2.3 How congestion affects market outcomes

As well as influencing the behaviour of market participants, congestion affects the market as a whole. First, it can increase the overall cost of electricity supply because it interferes with the objective of meeting demand at the lowest possible cost. Second, the physical and financial impacts of congestion, combined with participants' efforts to manage them, can potentially compromise the National Electricity Objective which is to "promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers".

In summary, congestion impacts market participants, affects their behaviour (in response), and has implications for short- and long-term market outcomes.

2.3 Managing congestion

To eliminate *all* transmission congestion would be neither cost-effective nor efficient. It would lead to over-investment in transmission capacity. In the NEM's radial network with dispersed sources of generation and centres of demand, the costs of building out all transmission congestion would be prohibitively high. There is, therefore, an *efficient level* of congestion, and it is this that needs to be managed.

The management of congestion can be considered narrowly, by focusing on specific mechanisms for dealing with congestion at particular locations, or more generally, by considering the framework that determines or influences behaviour in the presence of congestion. The Terms of Reference require us to look at congestion from both perspectives: the arrangements in general as they impact on the management of physical and financial risks arising from congestion, and the narrower question of the design of specific mechanisms for managing congestion at particular locations.

2.3.1 What is a Congestion Management Regime?

The incidence and materiality of congestion at any point in time depends on the behaviour of generators, large demand customers, investors, network businesses, and the market and system operator:

- Generators and large demand customers make bids and offers in the wholesale market, revealing the price at which they are willing to produce or consumer different volumes of electricity. In the longer term, generators, large demand customers and other investors also make investment decisions, for example to build a new power station or to close an existing one.

- Network businesses make decisions in the short term on which network elements are in service, and in the long term on what network elements to build or decommission. Collectively, these decisions define the physical network that is available to the system operator to dispatch flows across.

- The market and system operator NEMMCO makes decisions, based on market participant bids and offers and on the available physical network, as to which generators should run in any given five-minute dispatch interval to meet demand. It must make these decisions in a way that will maintain power system security and reliably meet supply.

The decisions made by generators and large demand customers in the shorter term, and by generators, large demand customers and investors in the longer term, will be conditioned by the need to establish contract positions and to manage risk in respect of those contract positions. A CM Regime is the set of rules that influence these decisions.

Given that it is not possible to manage congestion using a single rule or instrument, a range of measures are necessary. The challenge is to identify which combination of measures will promote efficient outcomes given the prevailing patterns of congestion and investment environment.

The MCE recognised the importance of identifying the inter-linkages between the various measures for managing congestion.[12] The Terms of Reference for this Review required us to examine the role of a location-specific interim constraint management mechanism that could be applied selectively, and on a time-limited basis, to a particular constraint. Such a mechanism is one potential element of a CM Regime.

Another key element of a CM Regime is the information available to participants. The Rules currently influence how participants respond to the physical and financial market risks arising from congestion. However, participants could make more informed decisions if they understood the nature of the risks better. The more information they have, the better their ability to manage those risks. Consequently, although under the current Rules some information on congestion has to be provided to the market, there will be a greater role for congestion-related information in a CM Regime.

In generic terms, a CM Regime will comprise Rules and information for the following elements of an electricity market:

- *Dispatch*—how the system and market operator decides which generators will run to meet demand. This will primarily influence market participants' perceptions of dispatch risk.

- *Wholesale market pricing and settlement arrangements*—how generators at different locations are remunerated in the spot market for their output. This, in combination with an understanding of the Rules for dispatch, will influence generators' bidding strategies. A location-specific interim constraint management mechanism is an intervention in the wholesale pricing and settlement arrangements that focuses on managing a particular constraint at a particular point in time.

- *Transmission access, pricing, incentives and investment planning*—how connection to and use of the transmission network is provided and charged to market participants, and how network augmentations are planned. These are another form of economic signal to market participants relating to the direct cost of connection and to the indirect impacts of network investment on pricing and dispatch outcomes in the longer term.

- *Risk management instruments* – what tools are made available through the Rules to enable market participants to manage basis risk.

2.3.2 Why manage congestion?

There are many reasons why it is important to manage congestion. It is necessary for maintaining the physical and operational security of the power system. It also has important implications for spot prices, the degree of competition, bidding incentives for market participants, and the levels of basis and dispatch risk borne by

12 CMR Terms of Reference, clause 3.2, p.4.

participants. In the long term, the manner in which a market manages congestion affects the investment decisions of new generators, load, network service providers, and the opportunities for alternative energy sources.

The approach taken to congestion management therefore plays an important role in:

- ensuring power system security and supply reliability;
- minimising the immediate cost of meeting demand; and
- ensuring that market participants receive the appropriate information about the cost and location of congestion, and therefore make appropriate investment decisions in the longer term.

An effective regime for managing congestion can assist electricity producers, large customers and transporters in managing risks and making informed decisions, and thereby promote efficient outcomes for all consumers.

2.4 Congestion to date

2.4.1 Evidence-based approach

Our recommendations have been informed by evidence on the prevalence and materiality of congestion in the NEM. Much of this evidence is based on experience in the recent past. While such historical evidence can provide valuable insights, it has its limitations. We need to be aware that in the future patterns of congestion might materially change, and we need to identify and understand the drivers for any such change. (These points are discussed further in Chapter 4.)

The available evidence also needs to be interpreted carefully. Over the short and long term we looked at the incidence, duration and location of congestion as well as at indicators of its economic costs. It is important to consider both incidence and economic cost. A high incidence of congestion does not necessarily mean a material market impact. On the other hand, a low incidence of congestion may have a significant impact on market dispatch. To get a complete picture of congestion in the NEM, therefore, we examined a range of indicators.

2.4.2 The evidence base

We considered the available historical data on the level and duration of congestion from several sources: the annual AER reports on the indicators of the market impact of transmission congestion; NEMMCO's Statement of Opportunities - Annual National Transmission Statements (SOO-ANTS); and work conducted by Dr. Biggar[13] and NEMMCO on the patterns of mis-pricing in the NEM. We also considered mis-pricing cost analysis prepared by Frontier Economics and a

[13] Dr Darryl Biggar is an economic consultant to the ACCC and AER and an advisor to us on the Congestion Management Review.

stakeholder report prepared by Intelligent Energy Systems (IES) that looked at the potential future long-term investment impacts of different pricing arrangements.[14]

2.4.3 Key findings from the analysis of the evidence

The data from the last four to five years showed that congestion in the NEM was unpredictable, with both the location and duration of significant binding constraints varying significantly. Also, most constraints had a relatively short "life–cycle", in that they caused some mis-pricing for only one or two years before being largely addressed by investment in transmission or generation infrastructure. There were only a few locations where congestion was persistent. Overall, with the exception of the Snowy region, congestion did not appear to be a major problem in the NEM.

Here are some of the key findings:

- Dr. Biggar concluded that the NEM-wide incidence of mis-pricing had increased since 2003/04. He found that mis-pricing was a frequent and enduring issue at a relatively large number of connection points, stating that some 95 connection points were mis-priced for an average of more than 100 hours per annum over the three years of his study (2003/04 to 2005/06).

- NEMMCO's preliminary study confirmed Dr. Biggar's finding that there had been an increasing trend in mis-pricing from 2003/04 onwards. However, it also showed that over the study period (2001/02 to 2005/06) the number of connection points being mis-priced was fairly steady. NEMMCO noted that the reasons for these trends were specific to the region and the situation at the time. NEMMCO also commented that the progressive conversion of "option 8" constraints to a fully co-optimised formulation would have contributed to the increase in frequency and duration of mis-pricing.

- Generators were significantly more likely to be positively mis-priced (constrained-off) than negatively mis-priced (constrained-on). In 2005/06 the ratio between the two forms of mis-pricing was 3 to 1.

- The average mis-priced amount per mis-priced dispatch interval was very high, ranging from around $500 to $1 000/MWh for generators that were positively mis-priced and from around -$300 to -$6 000/MWh for generators that were negatively mis-priced. These results suggest there is a high probability that dis-orderly bidding occurred when a constraint bound.

- Dr Biggar found that only a small number of connection points were mis-priced by more than $5/MWh for all three years of his study. These connection points all related to small gas or hydro plants in Queensland.

- Dr Biggar also found that the average hours of mis-pricing due to system normal events were fairly constant over the three years, at around 50 hours per year. However, there was an increasing trend in the duration of mis-pricing due to

[14] See Appendix B for more information about these sources and their findings.

transmission outages, from 20 hours in 2003/04 to over 120 hours in 2005/06. This was mainly due to the increased incidence of outage-caused congestion in both the Snowy and Queensland regions. The Queensland increase was due to a number of lightning events affecting flows between Central and South Queensland and an outage at the Gladstone transformer.

2.4.4 Material congestion in the NEM has not been substantial to date

In addition to considering the prevalence of congestion, we also looked at the economic costs of congestion over both the short and long term as well as the implications for risk management and contracting.

2.4.4.1 Short-term outlook

AER indicators

In terms of the short-term outlook, we examined the AER's indicators of the annual dispatch costs of congestion over the period 2003/04 to 2006/07. These indicators include the total cost of constraints (TCC), the outage cost of constraints (OCC), and the marginal cost of constraints (MCC) (see Table 2.1 below). All of these indicators involve a comparison between actual dispatch costs (based on participants' bids and offers) and hypothetical dispatch costs in circumstances otherwise identical (i.e. same bids and offers) except that no congestion occurred.

Table 2.1 AER indicators of the market impact of transmission congestion

	Total Cost of Constraints (TCC)	Outage Cost of Constraints (OCC)	OCC as % 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 within 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).

Converting the AER's measures into indices with a base year of 2003/04 revealed a near three-fold increase in the TCC and just over a six-fold increase in the OCC in the four years to 2006/07.

The assumptions and methodology behind these measures mean there are limitations to what conclusions can be drawn. That being said, the magnitude of the AER estimates was very small compared to the NEM's annual wholesale sales of $6 billion. Also, an increasingly significant proportion of the TCCs was related to transmission outages (over 50% in 2006/07), and the majority of the costs occurred on only a few days each year.

Frontier Economics' mis-pricing costs analysis

Frontier's analysis attempted to calculate the costs of dispatch inefficiency caused by generators bidding in a dis-orderly manner to avoid being either constrained-on or –off in a market experiencing mis-pricing. This analysis did not allow for any material market power, meaning that: (a) generators that were not mis-priced were assumed to bid their capacity into the market at their short-run marginal cost; (b) generators that were constrained-on were assumed to bid their capacity at $10 000/MWh to avoid being dispatched; and (c) generators that were constrained-off were assumed to bid their capacity at -$1 000/MWh in order to be dispatched. The modelling period was the 2007/08 financial year.

Frontier found that production costs in the scenario with mis-pricing across the entire NEM were $8.01 million higher than in the base case in which all generators were assumed to bid their capacity at short-run marginal cost. This represented 0.47% of the NEM's annual total production costs of more than $1.7 billion, which indicated that the impact of constraints binding and causing inefficiency through mis-pricing was relatively low.

Economic modelling of congestion in the Snowy region

The modelling we undertook on the various proposals for managing congestion in the Snowy region found that the dispatch efficiency impacts of eliminating mis-pricing, even in an environment of strategic bidding, were likely to be relatively small compared to the overall level of trade and welfare surpluses in the NEM.[15]

2.4.4.2 Risk management and contracting

As discussed earlier, congestion can contribute to participants' trading risks. The materiality of the financial risks arising from congestion depends on the availability and usefulness of risk management instruments. The "firmness" of an instrument represents the percentage of risk covered by that instrument. For example, an instrument that is 50% firm would only cover half of a participant's basis risk.

Our analysis found that the level of firmness of the inter-regional settlement residue (IRSR) unit instrument varied greatly across the NEM interconnectors, ranging from only 0.9% firmness for the Snowy-to-NSW interconnector to 90.7% for the NSW-to-Snowy interconnector. Most other interconnectors ranged between 60% and 80% firmness. The study found that the lack of firmness was caused by lower transfer capabilities, meaning that one IRSR unit represented less than 1 MW of interconnector flow at the time of the price differences. Negative settlement residues accounted for a very small percentage of the lack of firmness, in part due to

[15] See AEMC 2007, *Abolition of Snowy Region*, Rule Determination, 30 August 2007, Sydney.

NEMMCO's practice of "clamping" flows in some circumstances where negative settlement residues would otherwise accumulate.

Participants acknowledged the lack of firmness offered by IRSR units, but expressed concern about the risks of introducing major changes, especially if they were made in isolation from initiatives to improve transmission performance. We also found that participants' appetite for inter-regional trading varied greatly and that they used a portfolio of instruments to manage risk rather than just relied on a single mechanism, like IRSR units.

2.4.4.3 Long-term outlook

We need to understand the long-term implications of congestion as well as the short-term, especially in light of the significant amount of energy investment planned for the next five to fifteen years. We therefore considered several approaches and data sources in order to assess the long-term outlook. (We have also considered the potential impact on the materiality of congestion of future developments in the market, as well as the pressures these developments might exert on the current Rules and regulatory framework. These matters are discussed in Chapter 4.)

In its 2006 SOO-ANTS, NEMMCO estimated that the present value of the total market benefits of costlessly removing all network constraints would be $2.2 billion over the next ten years, with benefits arising from lower dispatch costs, deferral of capital expenditure, and reliability savings. It would be inefficient to build out all network congestion, however, and therefore such significant market benefits are unlikely ever to eventuate. So, while informative, this analysis has limited applicability to our Review.

We also considered a report by IES that estimated what the longer-term impact would be if all congestion in Queensland were priced. The report found that pricing arrangements for both congestion and transmission would lead to a more efficient pattern of generation and transmission investment. Furthermore, a scenario that combined both pricing arrangements yielded greater efficiencies compared to a scenario that relied solely on more granular congestion pricing.

The IES report represents an important and useful attempt to quantify the long-term market benefits of various pricing regimes. However, like the NEMMCO analysis, its applicability to our Review is limited. This is because the IES report contained simplifying assumptions which, while necessary and understandable given the limited time IES had to undertake such a substantial modelling exercise, were not reflective of the actual market environment. Specifically, the modelling did not factor in the risk implications and implementation costs of introducing greater locational pricing, nor did it include a review of whether the location of additional generation was plausible. This means that the cost estimates of the current regional pricing regime were probably overestimated because they did not account for factors that are potentially quite influential, such as the risk implications of 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, it is unlikely that the benefits would be as great as the report suggests. The case of the IES report also demonstrates just how difficult it is to quantify dynamic efficiency benefits.

2.4.5 Persistent and significant congestion in the Snowy region has been fixed

Market participants agreed that there has been significant material and enduring congestion in the Snowy region.[16] Although a number of temporary ad hoc measures have been implemented over recent years to address the dis-orderly bidding incentives triggered by this congestion, it remained unlikely that long-term investment would fix the problem in the foreseeable future. This was due to the high market cost that would result from taking the lines out of service in order to upgrade them and the environmental issues associated with development in the national parks across which the Snowy region lies.

For these reasons the Snowy region will be abolished on 1 July 2008. This will introduce a region boundary across the point of material and enduring congestion.[17] Abolishing the Snowy region will create the strongest incentives for generators to bid in a more competitive way. It will improve dispatch efficiency and will result in more cost-reflective spot prices. We expect that the shorter-term competitive benefits will impact positively on contract markets and provide clearer signals for efficient investment and consumption in the longer term, ultimately benefiting end-use customers. The abolition of the Snowy region is a proportionate and stable response to a major legacy congestion issue.[18]

16 AEMC, Congestion Management Review, Industry Leaders Strategy Forum, October 2006, Sydney.

17 See AEMC 2007, *Abolition of Snowy Region*, Rule Determination, 30 August 2007, Sydney.

18 This is the first substantial region change in the NEM.

3 Improving the Congestion Management Regime

Having given an account in the previous chapter of the prevalence and materiality of congestion, we now turn to the CM Regime and how it can be improved. The discussion focuses on our recommendations for improving the provision of information and for strengthening existing risk management instruments—incremental changes consistent with the NEM market design. We also explain why we are not recommending more extensive changes to how the wholesale market is priced, for example by introducing a location-specific interim constraint management mechanism.

When considering how a CM Regime helps promote efficient outcomes it is important to consider how its component parts combine to send to market participants economic signals that influence investment or behaviour at particular locations. For this reason we will begin by explaining the range of economic signals that already exist in the CM Regime. We will then turn to our recommendations for incremental but important change.

3.1 The nature of locational signals in the CM Regime

In the NEM today, the CM Regime provides a range of locational signals to market participants:

- *Price separation between regions*—congestion can lead to regional differences in the cost of supplying demand. In the NEM market design physical network constraints reveal themselves in the market through differences in the RRPs. Systematic differences in RRPs provide important signals as to where additional generation capacity might be most valued.

- *The prospect of changes to pricing regions*—the signals provided to investors through wholesale market pricing are also conditioned by the possibility of region boundaries being changed. In 2007 we amended the Rules to put in place a new process for changing region boundaries.[19] A case for region change must now be based on economic evidence of an enduring and material congestion problem. This means that investors need to factor in the possibility that congestion points which are not currently priced in the NEM region model, including new congestion points created by new investment, may be priced in the future as a result of a region boundary charge.

- *Transmission losses*—generators that are closer to centres of demand will, other things being equal, be cheaper (and therefore more competitive) than generators further away from demand. This is because of losses on the transmission system. Transmission losses are reflected in the market through the application of loss factors. There is a static loss factor for each point within a region (reflecting an annual average level of losses at that point), and there are dynamic loss factors which are calculated every five minutes for flows between regions.

[19] This new process commences on 1 July 2008.

- *Dispatch risk*—generators at different locations face different probabilities of not being dispatched due to constraints on the network. Other things being equal, a generator located at an uncongested point on the network will be more competitive than a generator located at a congested point on the network. This might reveal itself in an ability to offer greater volumes in the contract market at a more competitive price. It might also reveal itself in the form of a higher discount rate being applied by investors in considering investment options with higher dispatch risk.

- *Connection charges*—generators pay a "shallow" charge for the connection service provided by a TNSP. This charge reflects the cost of the assets required to connect the generator to the main interconnected network. Additionally, the Rules provide for generators to negotiate different levels of connection service. This may involve a generator agreeing to fund deeper reinforcement work on the transmission network in return for reduced dispatch risk. It may also involve a generator recouping some of the costs of deeper reinforcement work if new generators subsequently connect. These costs are forms of locational signal.

- *Regulated transmission investment*—TNSPs have obligations and financial incentives to invest efficiently in their networks. The Regulatory Test requires that network investment must be justified economically on the basis of meeting standards for reliability, or on the basis of delivering net market benefits. Any investment required by a particular generator over and above this must be funded by the generator itself (or the generator must accept the consequences in terms of dispatch risk). This is an important form of locational signal. The planned reforms to the Regulatory Test and the establishment of a NTP, as part of the implementation of national transmission planning arrangements, will improve the effectiveness of this form of signal.

- *Fuel access and transport costs*—other things being equal, a generator that is located close to its fuel source will be more competitive than a generator that incurs significant costs in transporting its fuel to its generating station. The relative cost of transporting fuel, as compared to locating at the fuel source and transmitting the generated electricity greater distances, is another form of location signal. Clearly, this is more relevant to some generating technologies (e.g. gas) than others (e.g. wind).

The locational signals provided through the CM Regime, including the prospective reforms to the Regulatory Test and the establishment of a NTP, play an important role in influencing decision-making by market participants. In addition, these factors may indirectly or directly influence investment decisions, for example whether to finance a project and, if so, what project and at what cost. It is how these signals combine, rather than the form or strength of a particular signal on its own, that matters when assessing their impact on the efficiency of outcomes for consumers.

3.2 Recommendations for change

In the following sections, we summarise our recommendations, explain how they incrementally improve the CM Regime and propose how to implement them.

3.2.1 Dispatch

Recommendations

We are recommending that the Rules be amended to clarify and strengthen the obligations on NEMMCO in respect of how it formulates the constraints used to dispatch the market. We are also recommending improvements to the provision of information to the market about events affecting dispatch.

With these changes, the Rules will require NEMMCO to:

- use a fully co-optimised network constraint formulation when dispatching the market, unless during pre-defined exceptional circumstances in which cases it can use an alternative constraint formulation (ACF);
- develop Constraint Guidelines for constraint formulation, constraint use and the policy for managing negative settlement residues;
- comply with the Constraint Guidelines; and
- publish in a Congestion Information Resource (CIR) any information about "planned network events"[20] that will materially affect network constraints.

We are also recommending that the Rules allow NEMMCO to intervene in dispatch to manage the accumulation of negative settlement residues, conditional on NEMMCO identifying its policy for intervention, including the trigger level which we recommend should be set at $100 000. We will review this policy and evaluate the further need for this intervention in three years.

Context

NEMMCO is both the system operator and the market operator. In its capacity as system operator, NEMMCO has the role of determining the volume of output of each generator at each point in time. This is the dispatch process. NEMMCO calculates the dispatch and communicates instructions to each generator (and large load) every five minutes.

The objective of the central dispatch process specified in the Rules is to maximise the value of trade in the spot market, subject to the constraint of maintaining the security and reliability of the power system.[21] This translates into an objective of minimising the total cost of dispatch based on the value of bids and offers. Implicit in this is an assumption that bids and offers accurately convey information about the cost of production and the value of consumption.

---

[20] Planned network events include: network outages; commissioning (or decommissioning) of new generating units, load or network assets; and new or modified network support agreements.

[21] The central dispatch objective is set out in clause 3.8.1 of the Rules.

A dispatch solution must be technically feasible. This means that the underlying physical network must be able to manage the resultant electricity flows and that NEMMCO's instructions to individual generators and large users must be consistent with their operating characteristics.

Constraint equations provide mathematical descriptions of the physical network. They explain how different variables, such as generator output, in the market affect flows across the network. NEMMCO uses constraint equations in the dispatch process and changes them to reflect changes in the available network. The process of designing constraint equations is known as constraint formulation. A "fully co-optimised" formulation is a form of constraint that gives NEMMCO the ability to control the most number of variables in the dispatch process.

In its capacity as market operator, NEMMCO performs the task of financial settlement. This is the process of paying generators for what they produce and billing users for what they consume. Producers and consumers within a region are settled at the same price, although different prices might exist between regions. In any given trading interval there can be net flows between regions. For example, the New South Wales region might be a net importer of electricity from the Queensland region. Ordinarily this will occur when the price in the New South Wales region is higher than the price in the Queensland region. In this scenario NEMMCO receives more money from consumers (in NSW) than it pays to producers (in Queensland). This difference creates an "inter-regional settlement residue" (IRSR).

In some circumstances, however, the dispatch might produce an outcome in which electricity flows from a higher-priced region to a lower-priced region, for example as a result of network constraints within a region. This will create a "negative" settlement residue. Negative settlement residues can adversely impact the ability of participants to trade efficiently across regions. The current arrangements provide for NEMMCO to intervene in the dispatch in some circumstances to manage the accumulation of negative settlement residues.

Reasoning

Clear Rules on dispatch mean that NEMMCO has a structured framework to operate under and that market participants have a better understanding of the dispatch process. A transparent and predictable central dispatch process provides certainty for generators and large customers, enabling them to make informed decisions on their bids and offers so as to manage perceived dispatch risks.

Our recommendations will improve the clarity of the dispatch process. They will provide greater transparency and predictability around the formulation, development and use of constraint equations. Constraint equations have a significant commercial impact as they can directly affect how generation and load are dispatched. By "hardwiring" the constraint form in the Rules and requiring a high degree of transparency and predictability around the development and use of constraint equations through the Constraint Guidelines, our recommendations will ensure that market participants have greater certainty as to how these factors will impact on their own dispatch.

Use of the fully co-optimised constraint formulation is a policy position endorsed by the MCE.[22] This particular formulation gives NEMMCO control over the most number of dispatchable variables (e.g. generator output), which improves its ability to manage power system security and supply reliability and to utilise more fully the network during the dispatch process. There are certain circumstances under which NEMMCO considers a constraint formulation that is not fully co-optimised (an ACF) will deliver greater security in the power system. While it is important for the system operator to have a level of flexibility in the Rules to use an ACF, participants must also have certainty around what constraint formulation NEMMCO will use in dispatch. This is why we recommend that NEMMCO should use an ACF in exceptional circumstances only, and that those exceptions should be explicitly identified beforehand in the Constraint Guidelines.

It is also important for generators and large customers to have certainty and predictability in circumstances where NEMMCO may intervene in dispatch. In general terms, physical interventions are inherently problematic and should, if possible, be avoided. Our recommendation to enable NEMMCO to intervene in dispatch to manage negative settlement residues is therefore sub-optimal. However, while NEMMCO's intervention is not an ideal response to counter-price flows, removing the intervention altogether could greatly distort generator bidding incentives. This has implications for risk management, as discussed below.

To provide the greatest certainty and predictability around this intervention, NEMMCO must set out its policy for when and how it will intervene in the market to manage negative settlement residues in the Constraint Guidelines. This includes setting its intervention threshold. We are recommending that this threshold should increase from $6 000 to $100 000, to reduce uncertainty for participants around excessive intervention in dispatch and to allow, in most cases, efficient dispatch to continue by delaying intervention. We will review NEMMCO's intervention policy in three years' time to assess whether we can remove it.

Lastly, generators and large customers can make more informed bids and offers if they have better information about which constraint equations will be included in dispatch improves participant decision-making. The recommended CIR will provide the most up to date information on network outages and other planned network events. This will provide participants with a better understanding of how potential changes in system conditions are likely to affect network constraints and therefore influence dispatch. This translates into more informed and efficient decision-making for participants.

Implementation

The *Draft National Electricity Amendment (Fully co-optimised and alternative constraint formulation) Rule 2008* (Constraints Draft Rule) articulates how to implement the recommendations for constraint formulation and the management of negative

[22] See the MCE's May 2005 Statement of NEM Electricity Transmission for more information.

residues.[23] It will formalise NEMMCO's use of fully co-optimised constraints and will set out the information NEMMCO must include in its Constraint Guidelines. This will include outlining its policy for managing negative settlement residues and ACF.

The establishment of the CIR is set out in the *Draft National Electricity Amendment (Constraint Information Resource) Rule 2008* (CIR Draft Rule).[24] This Draft Rule will require NEMMCO to develop and publish a resource that provides information in a cost effective manner to market participants to enable them to understand the patterns of network congestion and make projections of market outcomes in the presence of network congestion. This will include information on planned network events. The development of the CIR is to be continuous and incremental.

A Rule change is not necessary to increase the threshold trigger to manage negative settlement residues. NEMMCO can implement this through a change in its dispatch operating procedure. However, the threshold should not be increased prior to implementing the new recommended negative settlement residues recovery mechanism, discussed below in Section 3.2.3.

For more details on the implementation of these recommendations, see Appendix C. The Constraints Draft Rule and CIR Draft Rule are published in Appendix G.

3.2.2 Transmission access, pricing, incentives and investment planning

Recommendations

In 2006 we reviewed and substantially reformed the regulatory framework for transmission. In this Congestion Management Review we have considered whether further refinement is required, bearing in mind that the new regulatory framework has not been in operation for long enough to be able to assess its effects properly.

We have identified one area where amending the Rules will clarify and strengthen the framework. This relates to circumstances in which generators choose to fund a network augmentation in the context of negotiating its connection service with a TNSP.

Our recommendation is to make explicit the requirement that recouped costs (or reduced charges) should be negotiated between a generator and a TNSP and should apply to circumstances where another party connects to the network and benefits from an existing participant-funded network augmentation.

[23] The Constraints Draft Rule is published in Appendix G.

[24] The CIR Draft Rule is published in Appendix G.

Context

Transmission services and revenue regulation

Chapters 6 and 6A of the Rules address the economic regulation of transmission services. They set out the provisions for determining TNSP revenue allowances and pricing methodologies. These provisions seek to create appropriate financial incentives to support efficient decision-making by both TNSPs and participants in relation to investment in transmission, generation and load facilities.

The Rules classify transmission services into two broad categories – Prescribed Transmission Services and Negotiated Transmission Services. The provision of Prescribed Transmission Services is subject to a revenue cap, set every five years by the AER pursuant to a process defined in the Rules. The revenue cap is set to permit recovery, during the regulatory period, of depreciation and a reasonable rate of return on: (a) actual capital expenditure incurred before the start of the regulatory period; (b) a forecast efficient level of capital expenditure to be incurred during the regulatory period; and (c) a forecast efficient level of operating expenditure.

Revenue for TNSPs from the provision of Negotiated Transmission Services is not subject to a cap. The provision of new Connection Services is the main form of Negotiated Transmission Service. The Rules also provide for negotiated transmission network user access. The negotiation between a generator and a TNSP can include a generator agreeing to fund a network augmentation. A generator might do this if the network provided by TNSPs under the regulated incentives delivers an unacceptable (for the generator) level of dispatch risk. The Electricity Transmission Network Augmentation Connection Guidelines currently published by VENCorp provide further detail on how these arrangements can work in practice under the current Rules.[25]

The Rules set out a framework and principles for setting prices for Prescribed Transmission Services. They also set out principles for negotiating access for Negotiated Transmission Services. The Rules maintain a "shallow" connection charge approach for new generation. This means that generators pay charges related to the cost of the assets required to enable the electricity they generate to be exported on to the main interconnected network. The cost of the main interconnected network is recovered through charges levied on consumers.

In related work, we are currently reviewing the framework for transmission incentives from the perspective of incentives for TNSPs to explore and implement non-network (e.g. demand-side) options where they are more efficient than options based around transmission investment. We recently published an Issues Paper on demand-side participation in the NEM.[26]

---

25 http://www.vencorp.com.au/index.php?action=filemanager&folder_id=581&pageID=7770&sectionID=8246

26 AEMC 2008, Review of Demand-Side Participation in the National Electricity Market, Stage 2: Issues Paper, 16 May 2008, Sydney. Available: www.aemc.gov.au.

Transmission planning

A TNSP is responsible for investment planning in its area. The Rules stipulate a process of consultation and assessment that must be followed before investment is undertaken. This is the Regulatory Test. To satisfy the Regulatory Test, investment proposals are required to meet reliability needs or to deliver net benefits to the market. As noted in Appendix C (C.3.4), we are currently developing proposals to reform the Regulatory Test as it applies to transmission companies. These reforms, which are being undertaken at the direction of the MCE, will amalgamate the reliability and market benefits elements of the Test and establish a common framework for assessing costs and benefits across all projects.

We are also developing recommendations for the MCE on establishing a NTP. The NTP will publish information, including an annual NTNDP, setting out strategic, long-term development plans under a range of scenarios. This will not alter the accountability of individual TNSPs, but it will enhance the information available to TNSPs in undertaking their planning. This is likely to promote a more coordinated approach to the development of the NEM's transmission network over time.

The Rules also provide a "safety net" in the event of planning failure by a TNSP. This is the LRPP. The LRPP empowers us to oblige a TNSP to apply the Regulatory Test.

Reasoning

Negotiated transmission services are an important element of the overall CM Regime because they provide locational signals to generators considering investment options. The direct cost of connection provides one form of signal. The scope for generator-funded network augmentations provides another. This has relevance where the quality of access required by the generator is greater than can be supported by network investment consistent with satisfying the Regulatory Test.

A potential barrier to efficient responses to these signals is the risk that a generator who funds a network augmentation does not realise the full benefits of the augmentation because another generator connects subsequently. This is the "first mover" problem. The Rules provide for this contingency in two ways. First, they allow a generator to negotiate an explicit level of transmission network user access with a TNSP; for example, the generator could stipulate compensation payments if the level of service was reduced. Second, they allow costs to be recouped (or charges reduced) in the event that another user's connection impacts on the service being provided to the "first mover".

While the current provisions in the Rules already allow for such responses to subsequent connections to a "first mover"-funded augmentation, our analysis indicates that these provisions can be stated more clearly and directly. This includes making explicit the requirement that recouped costs (or reduced charges) should be negotiated between a generator and a TNSP, and not unilaterally imposed by a

TNSP.[27] We believe this clarification will provide greater certainty for generators, thereby improving the overall effectiveness of the locational signal.

A number of stakeholders made submissions on the current operation of this area of the Rules, citing a number of weaknesses. The National Generators Forum (NGF) also submitted consulting work undertaken for them by Synergies, which set out different models of transmission access. While we acknowledge and welcome the points made in submissions, the adoption of alternative models for transmission access would represent significant change to the NEM market design which we do not think can be supported on the basis of the current evidence on materiality. Such models might, however, have relevance to the longer-term development of the CM Regime, as discussed in the next chapter.

Implementation

The *Draft National Electricity Amendment (Network Augmentation) Rule 2008* (Network Augmentation Draft Rule) makes two amendments to the Rules to implement this recommendation.[28] The first is to include a drafting note in clause 6A.9.1(6) to clarify a point about adjustments in the costs for transmission access: where a network augmentation now provides a service to another party, costs can be recouped from that other party.

The second is to introduce a new clause 5.4A(f)(3) to clarify the point that when a generator and a TNSP are negotiating transmission access, including use of system charges, these negotiations should be conducted in a manner consistent with clause 6A.9.1.

The Network Augmentation Draft Rule is published in Appendix G.

3.2.3 Risk management instruments

Recommendations

We are recommending that the Rules be amended to change the method of funding negative settlement residues. Rather than being netted-off against positive settlement residues within the same billing week, and then any outstanding amount being recovered from Settlement Residue Auction (SRA) proceeds, they should be recovered directly from the importing region's TNSP. We are also recommending changing the design of the SRA so that auction units will be available up to three years in advance. The release profile of the quarterly units will be determined by the SRC.

---

27 The recommendation makes explicit the link between the principles for negotiating transmission network access under clause 6A.9.1 of the Rules and the rules on access arrangements for transmission networks in rule 5.4A.

28 The Network Augmentation Draft Rule is published in Appendix G.

Context

In the NEM's regional market, there is no price separation (and therefore no basis risk) within a region. Generators, large users and retailers contracting across regions, however, do face basis risk. These participants make use of financial contracts such as capacity swaps to manage this inter-regional risk. They can also purchase units to the IRSRs that arise when electricity flows between regions and the prices in those regions differ.[29] These IRSR units help fund any hedging contract payment shortfall that arises from inter-regional prices differences.

NEMMCO sells IRSR units every quarter at the SRA. Currently, SRA participants can bid for units up to one year in advance. There are units for every regulated interconnector in the NEM, in both directions. This enables participants to hedge price differences between all regions in both directions. The single exception is Tasmania where there are no IRSRs attributable to flows between Tasmania and Victoria.[30]

As discussed in section 3.2.1, dispatch can sometimes result in flows from a higher-priced region to a lower-priced region, resulting in negative settlement residues. The current funding mechanism for these negative settlement residues reduces the value of IRSR units as an inter-regional hedging instrument. Negative settlement residues are netted-off positive settlement residues within the same billing week for each same-direction interconnector. This reduces the positive residues available for distribution to unit holders.

If any negative settlement residues remain after the netting-off, they are recovered from SRA proceeds for the same-direction interconnector. SRA proceeds are what participants pay for IRSR units. TNSPs receive these proceeds to offset transmission charges.

Reasoning

Our recommendations all seek to improve the usefulness of the IRSR unit as a hedging instrument for generators, retailers and large users. The first recommendation will remove an arbitrary distinction in the Rules between funding negative settlement residues which occur in the same billing week as positive settlement residues, and funding those which do not occur in the same billing week. Removing this intra-week netting-off means that unit holders will retain the full value of residues accumulated from other events during a week, which will thereby improve the IRSR as a risk management instrument. The value of IRSR units will no longer be diluted because of events resulting in negative settlement residues.

Directly billing the relevant TNSP, who will then recover these costs through charges to its customers, is a more direct and transparent way to recover negative settlement

[29] The value of these residues is equal to the price difference between the regions times the flow between the regions.

[30] Tasmania is connected to the NEM through a Market Network Service Provider (MNSP), which is not regulated. There are no IRSRs attributed to flows across Basslink.

residues than via auction proceeds, as is currently the practice—although the net impact is broadly the same. This direct billing arrangement gives NEMMCO the flexibility to recover negative settlement residues in a timely manner rather than having to wait for the quarterly auctions.

These changes, coupled with an increase in the dispatch intervention threshold to manage the accumulation of negative settlement residues, will improve the value and usefulness of the IRSR unit as a mechanism for managing inter-regional basis risk.[31]

The redesign of the SRA to sell units up to three years in advance will improve their flexibility and usefulness for participants seeking hedge cover for their longer-term contract positions. It will potentially make secondary trading more likely, and thereby improve liquidity in the range of risk management tools available in the NEM.

Other important factors for strengthening the value of IRSR units are improving the reliability and predictability of transmission capability. If participants can accurately predict interconnector transfer limits, then with a high degree of certainty they can determine the required number of IRSR units necessary to hedge an inter-regional position. The CIR will provide information to participants to help them understand how the network's available network capability may change due to planned network events such as outages. Also, the NTP will be responsible for reporting on network capability as part of its NTNDP, which will provide an additional information resource for participants.

Implementation

The *Draft National Electricity Amendment (Negative Inter-regional Settlements Residue Amounts) Rule 2008* (Negative Residue Draft Rule) sets out the requirement for NEMMCO to recover negative settlement residues from the appropriate TNSP in the importing region.[32] Determining the appropriate TNSP to be charged will be the responsibility of the AER. This Rule will also enable NEMMCO to set a new TNSP settlement cycle for recovering negative settlement residues. This is to ensure that NEMMCO can recover the negative settlement residues from the appropriate TNSP in advance of the normal market settlement day, thereby preventing any potential shortfalls should the TNSP be late or miss a payment.

NEMMCO has confirmed that the process of extending the auctioning of IRSR units by three years is a procedural matter for it and the Settlements Residue Committee to consider. Therefore, no amendment to the Rules is necessary to implement this change.

NEMMCO has stated that in June 2008 it will start auctioning units for Q3 2009 (July–September 2009). The current negative settlement residues recovery

[31] The recommendation to increase the intervention threshold from $6 000 to $100 000 is discussed above in section 3.2.1.

[32] The Negative Residue Draft Rule is published in Appendix G.

mechanism is due to expire on 30 June 2009. In our view, it would be inefficient to consider reverting to the old recovery mechanism of auction fees when we are recommending a variation of the existing recovery mechanism. Therefore, it would be appropriate to extend the current sunset until the recommended new recovery mechanism can be implemented. We could give effect to this in the form of a savings and transitional arrangement in the Negative Residue Draft Rule.

For more details on the implementation of these recommendations, see Appendix C. The Negative Residue Draft Rule is published in Appendix G.

3.2.4 Wholesale market pricing and settlement arrangements

3.2.4.1 Information

Recommendations

We are recommending that the Rules be amended to require NEMMCO to publish analysis on the extent and pattern of "mis-pricing" caused by congestion and to update this analysis regularly. This information will form part of the recommended CIR.

Context

Information on mis-pricing represents a useful, robust measure of the incidence of congestion, which is specific to individual points on the network. In undertaking this Review, we requested NEMMCO to undertake detailed analysis of mis-pricing, which in turn informed the development of our recommendations. The NEMMCO analysis was published with the Draft Report.

Reasoning

The availability of information plays an important role in enabling market participants to understand, and therefore manage, the risks associated with congestion. The analysis undertaken by NEMMCO provided useful insights into the nature of prevailing patterns of congestion under system normal conditions and non-system normal conditions (e.g. in the presence of outages). Understanding patterns and trends in the incidence of congestion is also relevant to policymakers.

We therefore think that the analysis undertaken and published by NEMMCO especially for this Review should be updated and published on a regular basis. Incorporating this requirement into the recommended CIR will mean that the precise form this analysis takes can be refined over time in the light of stakeholders' views.

Implementation

The CIR Draft Rule (mentioned earlier in section 3.2.1) also requires NEMMCO to publish information on the incidence of congestion using historical data on mis-pricing.[33] It also clarifies the definition of mis-pricing, based on comments made in submissions to the Exposure Draft.

For more details on the implementation of this recommendation, see Appendix C. The CIR Draft Rule is published in Appendix G.

3.2.4.2 Generator constrained-on payments

Recommendation

We are not recommending implementation of a constrained-on payments regime through changes to the Rules on settlement of the spot market. This is because it would not represent a proportionate means of improving the management of physical and financial trading risks arising from network congestion.

Context

A generator is constrained-on if it is dispatched at a level of output above what it is willing to supply at the prevailing RRP. In other words, it values its generation at a price greater than what it will receive. It is an example of mis-pricing. This can occur as a consequence of the dispatch process. If a generator's output can help relieve a constraint, and thereby enable cheaper generation from elsewhere to supply load at the RRN, then that generator may be dispatched, despite its bids being above the RRP. While the market as a whole may be better off, the generator constrained-on may not be.

It has been proposed that a constrained-on generator could be compensated by a form of congestion pricing that would supplement its settlement price above the RRP. This is known as a "constrained-on payment".

Reasoning

While constrained-on payments would address one type of mis-pricing in the NEM, they raise several concerns. First, imposing a constrained-on payment regime through the pricing and settlement arrangements may be viewed as pre-empting a transmission response under Chapter 5 of the Rules.

Second, constrained-on payments may create the scope for the exercise of transitory market power by constrained-on generators, especially where a generator owns a portfolio of plant around a transmission loop. For example, take a congestion pricing scheme, such as a CSP/CSC mechanism, which would be equivalent to a pay-as-bid settlement approach for the volume of output being constrained-on. Potentially acute pockets of transitory market power could arise because generators' bids would affect the price they receive.

---

[33] The CIR Draft Rule is published in Appendix G.

There is also the question of how to fund constrained-on payments. Most constrained-on payment regimes need an external funding source to cover the payments.

An alternative scheme would be for generators constrained-on through the dispatch process to receive compensation as if NEMMCO had directed them generate. This could address the concerns about potential market power because the constrained-on payment would not be based on the value of the bids for the volume of output being constrained-on. Rather, the compensation would be based on a pre-determined calculation, which could be based on costs, or agreed to in a negotiate-arbitrate framework. Nevertheless, the need to source external funding for the payments would remain.

Finally, on the key issue of materiality, historically there has been a lower incidence of constrained-on generation than constrained-off generation. For example, for the three years from 2002/03 to 2005/06 there were on average around 40 connection points in the NEM that were constrained-on—about half the number that were constrained-off. This evidence does not support a case for change at this time.

In addition, there is evidence that the existing transmission responses are working effectively. The contractual arrangements between generators and TNSPs being used in the context of network support provide incentives for generators to generate when they otherwise may not have generated.

3.2.4.3 Location-specific interim constraint management mechanisms

Recommendations

In order to improve the management of physical and financial risks associated with congestion, the MCE's Terms of Reference requested that we develop a location-specific interim constraint management mechanism. The aim of such a mechanism is to provide an immediate (and temporary) "fix" to a material constraint until it can be addressed permanently through investment or region boundary change. We have carefully considered this type of mechanism, but we are not recommending that it be implemented as a permanent fixture of the NEM's regulatory framework.

Context

The MCE requested that we develop a location-specific interim constraint management mechanism as a way of improving the ability of participants to manage the physical and financial risks arising from network congestion. The MCE also required us to take into account the detailed work undertaken by CRA on these issues, as well as the trial arrangements in place in the Snowy region.

Generic framework for location-specific interim constraint management mechanisms

There is a wide range of detailed designs for a location-specific interim constraint management mechanism, and they are all based on a common framework.[34] The framework involves isolating a particular network constraint (or related set of network constraints) and amending the rules for calculating prices in the wholesale market in the event that the constraint binds.

If a constraint binds, then the cost of supplying demand at different locations can vary. This is because a binding constraint might limit the ability to use a cheaper source of generation to serve demand at one location, but not at another location. Cost-of-supply variations between RRNs are reflected in RRPs. But cost-of-supply variations between RRNs and other locations within the same region are not reflected in wholesale market prices. A location-specific interim constraint management mechanism introduces the possibility that cost-of-supply differences relating to particular network constraints will be reflected in prices in the market.

A location-specific interim constraint management mechanism works by removing the arrangement whereby a generator is settled automatically at the RRP for its dispatched volume of output. Instead, under the mechanism a generator is settled at a price more closely aligned to the cost-of supply at the generator's specific location. The degree of alignment depends on the range of network constraints included in the particular location-specific interim constraint management mechanism.[35]

In addition, the mechanism also generally involves the allocation of pre-defined "rights" to receive the RRP for specified levels of output. These rights can, depending on the design of the mechanism, be allocated according to a pre-defined administrative rule, for example as a fixed percentage of the available capacity, or through a market mechanism such as an auction.

The collective impact on a generator subject to a location-specific interim constraint management mechanism is, therefore, that it will receive the RRP up to a specified output limit and then be exposed to a price more closely related to the local cost of supply (its "nodal price").

Experience from the Snowy trial

A location-specific interim constraint management mechanism has been applied on a trial basis in the Snowy region since 1 October 2006. Having analysed this trial as part of our assessment of a range of Rule change proposals relating to congestion in the Snowy region, we established that the mechanism promoted more efficient outcomes only in circumstances specific to that region. The experience of the Snowy trial is not readily transferable to other parts of the NEM, for these reasons:

---

34 Gregan, T, and E Grant Read, "Congestion Pricing Options for the Australian National Electricity Market: Overview", prepared for the AEMC, February 2008. Available at: www.aemc.gov.au.

35 At the extreme, if the mechanism included all network constraints at all times, then it would approximate to calculating a separate price for each location (or "node") on the network.

- In the Snowy region the congestion problem was enduring and stable. It reflected a significant constraint between Murray and Tumut that could not be addressed by either network or generation investment for topographical reasons and because the area is a national park. In contrast, NEMMCO's mis-pricing analysis from 2001/02 to 2005/06 indicated that patterns of congestion in other parts of the network have been transitory, including a large (and growing) proportion of mis-pricing occurring at times of network outages.
- The Snowy trial also involved only one generating company. Hence, design issues relating to the allocation of rights to be settled at the RRP across competing parties did not need to be addressed.

In conclusion, while the Snowy trial provides useful context for some of the issues involved in assessing the case for location-specific interim constraint management mechanisms more generally, it has limited applicability.

Reasoning

We have sought to assess the costs and benefits of introducing a location-specific interim constraint management mechanism with reference to the National Electricity Objective of promoting economic efficiency and a stable, proportionate regulatory regime.

Scope for greater productive efficiency

The benefit of a location-specific interim constraint management mechanism is that it strengthens incentives for generators to submit bids which are reflective of costs. This reduces the problem of dis-orderly bidding in the market, i.e. generators using bidding as a means of managing dispatch risk. Dis-orderly bidding can be a source of productive inefficiency. The lack of cost-reflective bidding in the presence of congestion can increase the overall costs of meeting demand.

However, our analysis indicates that the productive inefficiency costs associated with dis-orderly bidding have been relatively low. The analysis undertaken for this Review by Frontier Economics and published with our Draft Report indicated that productive inefficiencies were in the order of $8 million per year (for the 2007/08 financial year).

Greater complexity in managing basis risk

A location-specific interim constraint management mechanism reduces incentives for dis-orderly bidding. This has an indeterminate impact on aggregate dispatch risk. In some cases, dis-orderly bidding can deliver relatively predictable dispatch outcomes, for example because of the application of "tie-breaking" rules in instances where all generators bid the same price. In other cases the potential for dis-orderly bidding can increase perceptions of dispatch risk, for example because of errors in predicting when dis-orderly bidding is likely to occur.

However, the introduction of a location-specific interim constraint management mechanism unambiguously adds to the complexity of managing basis risk. It increases the number of potential prices in the market. A generator subject to a location-specific interim constraint management mechanism therefore has to manage the risk of price separation between RRPs, and between its location and its RRP. This might be a particular challenge when a generator has entered into a contract prior to a location-specific interim constraint management mechanism being implemented. The materiality of this impact depends in part on the form of the instruments created as part of a location-specific interim constraint management mechanism for managing this risk, for example the form of the right to be settled at the RRP.

Significant implementation issues

To establish location-specific interim constraint management mechanisms more pervasively in the NEM requires the resolution of two significant implementation issues. (The experience of the Snowy trial is of limited value in this regard, due to its uniqueness.)

First, how should the constraints be identified to which the mechanism should be applied? NEMMCO's analysis of the prevailing patterns of congestion in the NEM shows that much congestion has been transitory (including a large proportion which coincides with network outages). In this context, even if the relevant constraints could be clearly identified, the mechanism would need to be implemented at short notice in order for it to be beneficial. The short notice period to implement would probably exacerbate the challenge of managing basis risk in the presence of such a potential mechanisms. The MCE recognised the potentially disruptive inputs of change to the pricing and settlement arrangements by requiring that a region change could only be implemented with three years notice.

Second, how should the entitlement to be settled at the regional rather than the local price be allocated across the range of potential parties subject to a specific mechanism. Under the current NEM design, these entitlements are allocated implicitly to match dispatch volumes. A location-specific interim constraint management mechanism would require an alternative method of allocation. How these entitlements are allocated will impact on the ability of market participants to manage basis risk in the presence of a mechanism. There are two broad approaches that could be adopted:

- *Administrative rule.* The mechanism could use a pre-defined rule, for example pro-rated shares of the available constrained capacity. The rule would also need to allow for the possibility of including newly-connected generators in the mechanism.

- *Market mechanism.* The mechanism could define new financial instruments that would provide rights to be settled at the RRP, and release them for sale, for example through periodic auctions.

There are challenges with both of these approaches. An administrative rule runs the risk of replacing one set of incentives for inefficient behaviour (e.g. dis-orderly bidding) with another. For example, a method based on pro-rated shares of each generator's available capacity might sharpen incentives for generators to overstate their available capacity, which might compromise NEMMCO's ability to operate the system efficiently.

The treatment of new generators is also a challenge. Some stakeholders have suggested that a location-specific interim constraint management mechanism should allocate available network capacity between existing generators, with new generators being settled at the local price for all of their output. This would skew the Rules in favour of existing generators, and potentially affect the efficiency of the competitive process. It might be more efficient (e.g. due to proximity to fuel source) for a new generator to connect at a congested part of the transmission network. A location-specific interim constraint management mechanism could, therefore, create new types of barriers to new entry, for example by creating additional basis risk, but no tools for managing it (other than through secondary trading with incumbent generators, if that were permissible under a location-specific interim constraint management mechanism).

In contrast, a market-based approach to allocating financial rights under a location-specific interim constraint management mechanism would not raise the same competition issues as an administered rule, but would involve significant additional complexity for market participants. In a relatively simple congestion management mechanism such as the Snowy trial, the number of constraints involved is large. If there were individual auctions for financial rights in each constraint, then there would be a significant number of auctions. There is an implementation cost to establishing the infrastructure to support such financial instruments, as well as a compliance cost for market participants.

Limited impact on locational signals

A location-specific interim constraint management mechanism would address disorderly bidding. However, the benefits in terms of greater productive efficiency would be, based on the evidence, relatively low. It could also impact the management of basis risk, and it would require the resolution of a number of significant implementation issues. There might, nevertheless, be net benefits from such a mechanism if there were evidence of other classes of benefit, for example if the mechanism's presence contributed to dynamic efficiency, i.e. the efficiency of decision-making (including investment decisions) over time.

As discussed above (section 3.1), under the current NEM design and Rules there is a range of locational signals. We are not persuaded that a location-specific interim constraint management mechanism would strengthen or clarify these signals. This is because such a mechanism is uncertain and temporary in application. Hence, the pricing outcomes that might result from its implementation are also uncertain. When prospective investors make decisions to invest, they will not generally know whether or not (or how) a particular project will be affected by a location-specific interim constraint management mechanism. It could also be argued that uncertainty as to whether a project will be priced regionally or locally (for an unspecified period of time) would reduce the clarity of existing locational signals by creating more regulatory "noise". Under either scenario, a location-specific interim constraint management mechanism would not improve locational signals for investment.

In addition, a location-specific interim constraint management mechanism may also add to the uncertainty of power project financing by compromising the ability of participants to access financing for investment purposes. While not specifically a locational decision factor, this directly affects whether or not investment will take place.

4 Ongoing evolution of the NEM's CM Regime

4.1 Where this Review concludes

The recommendations made in this Final Report deliver, in our view, an effective and proportionate response to the prevailing patterns and economic materiality of congestion in the NEM. They represent an important first step in the CM Regime's ongoing evolution.

Our recommendations in this Review complement other significant reforms to facets of the CM Regime: the abolition of the Snowy region; the new process for region change; the Last Resort Planning Power; the framework for economic regulation for transmission; and the establishment of national transmission planning arrangements. Collectively, this represents a significant package of reforms which supports efficient outcomes consistent with the National Electricity Objective.

4.2 Future market development

Prospective policy changes, most notably an Emissions Trading Scheme (ETS) and an extended Mandatory Renewable Energy Target (MRET), are likely to have significant impacts on the underlying economics of the market, and therefore behaviour in the market. These policy changes are occuring at a time of general tightening in the balance between supply and demand, which, in any event will require significant new investment in generation and network capacity. In this context, an important question will be whether the current Rules and regulatory framework continue to represent an effective and proportionate means of promoting efficient outcomes, given the potential changes in behaviour. This question encompasses the CM Regime and its effectiveness, if the pattern and economic impacts of network congestion change substantially.

There remains significant uncertainty about the detailed design of the ETS. It is therefore too soon to conclude on what, if any, consequent changes might be required to the Rules and regulatory framework to continue to support efficient outcomes. Hence, we have not sought to identify additional recommendations in this Final Report. Rather, we have sought to outline some of the potential impacts resulting from policies such as ETS and MRET and set out our views on the need for future review processes. This is consistent with our role under the National Electricity Law in respect of market development.

It is important and appropriate to consider these potential impacts in a broad context. The implications for the Rules include, but are wider than, the details of the CM Regime. There are many interactions between changes to the CM Regime and changes to other aspects of the regulatory framework, and partial assessment runs the risk of unintended consequences and less efficient outcomes.

This chapter considers these issues in more detail and highlights interactions between other related policy initiatives, such as the establishment of a National Transmission Planner and reform of the current Regulatory Test for transmission investment decisions. It also documents some of the options which might have relevance to this debate, including options for change which have been raised by stakeholders through the course of this Review but which, in our view, fell outside its scope.

4.3 Interactions between climate change policies and the NEM

This section sets out our initial thoughts on the main areas of interaction between climate changes policies, and behaviour and outcomes in the NEM. Further work and policy definition is required to analyse these interactions fully, for example to identify potential weaknesses in the Rules or regulation framework.

4.3.1 Merit order and dispatch

The merit order is the cost ranking of generators. If generator bids reflect costs, then the merit order will be reflected in the dispatch; that is, whether and to what extent each generator operates at any point in time.

An ETS will increase the operating costs of generators in line with their CO_2 (carbon dioxide) emissions. In general, this will increase the costs of coal-fired plant more than it will the costs of gas-fired plant; the amount will vary depending on the fuel source, plant type and operations. This will improve the competitive position of gas-fired plant in the NEM, other things being equal. This might, however, be offset by higher gas prices (and therefore higher costs for gas-fired generators). Such a change is likely to increase the level of gas-fired generation when compared with scenarios without an ETS. It may therefore lead to a change in the merit order and to the displacement of coal-fired plant by gas-fired plant.

An MRET and ETS will also increase the penetration of renewable generation. A key component of this will be wind farms.[36] Typically, wind farms have high capital costs and low operating costs. They are also often highly contracted. These factors may increase their incentives to bid at very low prices. Intermittent generation, such as wind farms, is therefore likely to be one of the lower-cost forms of generation bid into the market. Historically, intermittent generation has been unscheduled. Essentially this means that the plant ran without its dispatch being centrally controlled to minimise costs or maintain network security. Recently the Rules have been changed to provide NEMMCO with a greater degree of control in the dispatch process over larger wind farms. Much larger volumes of intermittent generation operating high up the merit order are likely to create new challenges for system operation, such as the management of efficient levels of reserve and the procurement of ancillary services.

If the position of coal-fired generation in the merit order changes, this might also raise a number of issues. Much coal-fired plant is optimised to run almost continuously at stable levels of output. If in the future it were required to operate more intermittently than it has done in the past, this might give rise to technical

[36] A disproportionately large proportion of wind generation is located in South Australia and Victoria.

challenges and cost (and therefore price) implications which are as-yet unknown. It might, for example, affect the need for generation reserve, operating reserve and the efficiency of energy and FCAS markets.

4.3.2 Generation investment

Investment is generally underpinned by long-term contracts between generators and retailers or major consumers. Investment is also made on a merchant basis (that is, taking risk on future pool prices). In both cases investors require a reasonable ability to forecast costs and revenues. If high risk attaches to costs and revenues, then investors will require higher returns, or they will not invest.

Investors are familiar with managing risks such as price volatility, changes in contractor costs and changes in fuel prices. However, it is harder for investors to assess and price and manage risk associated with government policy change. One of the impacts of climate change policies is, therefore, the uncertainty they produce in the market while the detailed design of each policy is being determined and legislated.

The introduction of an ETS may benefit gas-fired generation. However, gas-fired generation faces downside risk from a rapid increase in renewable generation due to the MRET. It also faces pressure in terms of fuel costs given the alternative markets for gas (e.g. exporting as LNG), and transport costs and practicalities (e.g. extending the gas transmission network).

A large increase in renewable generation will also alter the way in which investors recover their capital costs. In an energy-only market, such as the NEM, capital costs are recovered and profits are realised through the differential between variable operating costs and system marginal price. In most cases renewable generation will have low or zero operating costs. It will therefore displace output from fossil fuel plant and reduce the energy output from that plant. Investors may require a higher energy price to recover capital costs, depending on their position in the merit order. It is currently difficult for investors to assess these impacts.

If levels of uncertainty result in the deferment of generation investment such that reserve levels become unacceptably low, then one potential impact is that NEMMCO will have to make more frequent use of market interventions, such as directions and the “Reserve Trader”. The Reserve Trader is a form of market for capacity. If used more extensively, it might be necessary to review other forms of capacity market, such as markets for standing reserve.

4.3.3 Network investment

MRET will result in a large increase in new generation investment. The scale, location and timing of that increase will depend on decisions about scheme design, other economic signals in the market, and the practicalities of where it is feasible to build. (For example, opportunities for building new generation will be restricted by planning consent issues relating to environmental impacts on local communities).

The availability of wind and, where relevant, geothermal, solar and other renewable resources varies across the eastern seaboard. It is probable that some sites will have to be located at a long distance from load. It also seems probable that new wind generation will continue to be located in South Australia and Victoria disproportionately to other regions.

This raises the question of how to ensure efficient outcomes for investment in renewable generation. Issues include the costs of connection to the grid; the possible costs of grid reinforcement elsewhere; the impacts on network security of dispatch within security constraints; and the possible benefits from creating transmission links which can be used by other remote renewable generators.

The NEM currently makes use of regulated, negotiated and unregulated approaches to transmission investment. Regulated transmission revenues within a region are usually recovered through the region's transmission use of system (TUOS) charges. These arrangements determine how the risk of transmission investment being "stranded" is allocated between market participants and consumers. In broad terms, if a network investment satisfies the Regulatory Test, then the cost of the investment is underwritten by consumers (even if the investment proves, with the benefit of hindsight, to have been unnecessary). Investments that do not satisfy the Regulatory Test are, in effect, underwritten by the generator that contracts for them to be built.

The approach to charging out the costs of regulated investments may also need to reconsidered. If a disproportionate share of investment in remote renewable generation falls in South Australia and to a lesser extent in Victoria, this may raise efficiency and equity concerns if the associated transmission investment is funded by consumers in those States. This may require consideration of approaches to "inter-regional TUOS". We are currently consulting on this issue in the context of our review of national transmission planning arrangements.

A related set of issues includes the impact of renewables on planning of the overall transmission grid, and the interaction between new gas-fired generation, gas pipelines and transmission investments, notwithstanding the limitations on gas as a fuel source as discussed above. Both gas generation and gas pipeline investment are likely to be the result of private, "at-risk" decisions. However, the scale and speed of the investment required may be large and may therefore raise concerns about generation security. In addition these decisions will influence, and be influenced by, decisions on the transmission network.

4.3.4 Retail markets

The retail market relies on decentralised decision-making. Consumers are free to move between retailers, creating competition and incentives for retailers to meet consumer requirements efficiently.

Retailers in each jursidiction are required to supply energy to small customers at a regulated retail price.[37] To protect the smallest energy customers against ineffective competition, the prices charged by incumbent retailers in each region remain regulated at State level. We have been directed by the MCE to review the effectiveness of retail competition in electricity and gas retail markets (except in Western Australia[38]) and to provide advice on the future of retail price regulation.[39] Where we find that competition is effective, we provide advice on ways to phase out retail price regulation. We completed the review of Victoria in February 2008, and are now working on the review of the South Australian market.

Climate change polices may affect the efficiency of retail price regulation in two ways. First, they are likely to increase wholesale energy costs. Depending on the regulatory framework, it may not be possible to accurately forecast cost changes and reflect them in the regulated retail price. In the absence of a defined mechanism for cost pass-through, this could affect retail competition. It increases the likelihood of financial distress in the retail sector. This has implications for the generators that contract with these retailers. If retailers are unable to meet their contractual obligations, this can, in turn, affect the financial viability of the generator counter-party. While distress or insolvency is a legitimate risk in any market, including the NEM, it is more problematic when regulatory structures are a contributing factor.

Second, additional regulations applying to retailers (both host and new entrants) have been or are being introduced in response to climate change policies. These include MRET (and similar State-based targets which will be incorporated into MRET), energy efficiency targets, and a possible role in solar feed-in tariffs which are being mandated in several States.

The rationale for these measures is often the ability of retailers to cost effectively influence consumer behaviour. The measures may affect retailer costs and so, as with other climate change policies, may require regulatory pass-through. In so far as these schemes create administrative overheads, they may also act as a barrier to entry and reduce the effectiveness of retail competition.

4.4 Interactions with the CM Regime

The growing need for new investment resulting from the tightening supply/demand balance, and the changing cost structures resulting from policy responses to climate change are, collectively, likely to put new and different pressures on the CM Regime.

---

37 There is one exception. From 1 January 2008, retail price regulation for small business customers in Victoria was removed.

38 The Economic Regulation Authority (ERA) of Western Australia is required to undertake the review for its jurisdiction at an appropriate time.

39 The Terms of Reference to these reviews is available on our website: http://www.aemc.gov.au/electricity.php?r=20080115.175820.

4.4.1 Locational investment decisions

The previous chapter described in some detail the range of signals that currently exist which inform investment decisions in the market. The implementation of ETS and MRET will alter the underlying economics of investment options for new generation capacity. It will boost the relative competitiveness of low-carbon, and in particular renewable, technologies and therefore make investment in these types of generation technologies more attractive. In the NEM's framework of open access to networks this is likely to reveal itself in a significant number of new applications for connection. This situation is magnified by the tightening supply/demand balance, which would require new investment in generation capacity in any event to ensure that demand continues to be met reliably and securely.

There is still significant uncertainty as to how, precisely, these new initiatives will impact on the underlying economics of investment decisions in the market. A key driver will be the extent to which the rights to emit carbon are allocated to existing generation capacity. It is therefore too soon (i.e. in this Review) to conclude that the current set of economic signals for investment are not sufficient to promote dynamic efficiency. This is particular so, given that climate change policy direction has only crystallised at the end of this Review process—after the Draft Report was published. While we could continue with the Review, in the light of these new developments, we see value in concluding the Review at this point but at the same time highlighting the potential need to continue to consider the case for further change through a different, more holistic process. The issues involved are wider than congestion management, and should be considered and assessed as such.

Potential further developments also need to be carefully considered in the context of other changes that are in train. For example, the establishment of a National Transmission Planner and the introduction of a new Regulatory Investment Test for Transmission will also affect the locational signals for investment in the market, and interactions between these reforms and any elements of the CM Regime need to be fully analysed before the case for further change can be determined.

We have an important role to play in contributing and focusing debate on these issues and in ensuring that the technical detail and impacts of different changes to the NEM design are visible and fully understood in the context of the wider policy debate on reducing Australia's carbon emissions and promoting renewable forms of generation. If there is a perceived need to sharpen locational signals in the market, then it is important that the different options are understood from the perspective of both theory and practical implementation.

In the previous chapter, we set out our reasoning as to why we are not persuaded that a location-specific interim constraint management mechanism, like CSP/CSC, will promote the National Electricity Objective, including strengthening locational signals, given the prevailing patterns and economic materiality of congestion at this stage. While in a location-specific and time-limited manner a constraint management mechanism does address the "dis-orderly bidding problem", its presence is unlikely to be the determining factor in investment decisions, and therefore it will not address the "location decision problem".

There is likely to be a wide range of reform options to be considered in response to analysis indicating that material transmission congestion will probably emerge as a consequence of changes to the underlying economics of the NEM. It might, for example, require re-evaluation of location-specific interim constraint management mechanisms as a transitional device, if new and stable points of material congestion emerge, for example as a result of timing differences between generator and network investment responses. Use of such a mechanism in this manner, however, would still require resolution of the outstanding design and implementation issues discussed in chapter 3 above. For example, individual applications of the mechanism would probably require a specific design for each location, because a generic model does not appear to be a practical option.

A more extensive reform option would be the introduction of Generator Nodal Pricing (GNP) on a NEM-wide basis. Compared to a location-specific interim pricing intervention, GNP would solve the dis-orderly bidding problem in a more predictable manner, and would be more effective at addressing the locational decision problem. This is because GNP would explicitly price all congestion in the NEM as it arises.

However, GNP represents a significant change to the NEM market design, and would require a complete overhaul of the market architecture for managing the price risk that every generator would now face. It consequently places much greater emphasis on the need for effective risk management instruments, such as Financial Transmission Rights (FTRs). As a companion piece to this Review, we have undertaken initial but substantial analytical work on the potential application of GNP. We commissioned Frontier Economics to undertake the initial work. The Frontier Economics report, and its review by Professor Grant Read of EGR Consulting, are published with this Final Report.[40]

4.4.2 New patterns of congestion

ETS and MRET impacts might also drive different dispatch outcomes. This will affect flows across the network. The bidding behaviour of generators, and changes to the merit order of dispatch, will happen more quickly than networks can respond. Similarly, we might observe new generation capacity connecting more quickly than the efficient downstream augmentation of the network can occur—a strong possibility given the relative lead times for new generation capacity and new transmission investment. This might result in new and different patterns of congestion, reflecting different sets of incentives for dis-orderly bidding.

In these circumstances, dis-orderly bidding might be more material in its effects than is presently the case. Further, changes in flows might result in new locations of pockets of systematic, enduring and material congestion, such as exists in the Snowy region. In these circumstances there might be a role for a localised, time-limited

[40] Frontier Economics, "Generator Nodal Pricing – a review of theory and practical application", Report prepared for the AEMC, April 2008, Melbourne. Read, E.G., "Generator Nodal Pricing: Review of a report by Frontier Economics", prepared for the AEMC by EGR Consulting, 1 May 2008." Available on: www.aemc.gov.au.

intervention of the form trialled in the Snowy region. Note that in our analysis of the Snowy trial, the trial was shown to support more efficient outcomes than the status quo. On the other hand, more NEM-wide granular pricing would price congestion if and when it arises without the difficulties of implementing an individual pricing mechanism on an ad hoc basis. As discussed in chapter 3, however, introducing more granular pricing in the NEM has its own implementation issues.

The design of any option will need to be tailored to the specifics of the situation. The Rule change process is an appropriate mechanism for considering and implementing such an intervention, informed by the wide range of previous work (including Gregan and Read[41]). During the course of this Review, stakeholders presented a range of proposals. Some proposed significant change, like full CSP/CSC, while others proposed less substantial options for change focused on addressing dis-orderly bidding in the presence of congestion.

A recent proposal from a group of generators[42] is an example of the latter type. This proposal would retain the regional market design but, in the presence of congestion, would replace the existing right to settlement at the RRP with an alternative form of right that would eliminate incentives to bid in a dis-orderly manner. Babcock and Brown Power and Hydro Tasmania suggested similar arrangements. There may be scope to consider these less extreme options as a way of managing the dis-orderly bidding incentives that may arise in the presence of congestion.[43]

4.5 The need for a co-ordinated approach

The nature of the interactions between the efficient operation of the NEM and policy responses to climate change, in the context of a tightening supply/demand balance, are complex and multi-faceted. There is also significant uncertainty currently because the design issues are not yet resolved. This uncertainty in itself creates its own challenges for the efficient operation of the NEM in the short- to medium-term.

As the detailed policy design questions become resolved, we will have a clearer understanding of how precisely the market is likely to evolve—and how effectively the market design and Rules, including the CM Regime, will continue to support efficient outcomes. It is therefore timely to consider what impact climate change policies, such as ETS and MRETs, may have on the NEM and whether the current Rules and regulatory framework will continue to provide an efficient and proportionate means of promoting efficient outcomes.

It is important that the principles that have guided this Review continue to apply to any future review. Reform should be proportionate and based on sound evidence and reasoning, developed in the light of active stakeholder engagement. A future review should take into account:

---

41 Gregan and Read, “Congestion Pricing Options: Overview”.

42 The group of generators included: TRUenergy, International Power, Flinders Power, AGL and LYMMCO.

43 See Appendix D for a more detailed discussion of these proposals.

- the recommendations made in this Review;
- the recommendations to create an NTP, reform the Regulatory Test, and introduce a framework for nationally consistent transmission planning standards; and
- other related reforms already implemented, such as the change to the Snowy region, the process for region change, the LRPP, and the transmission regulation framework.

Given the extensive range of interactions, partial assessment runs the risk of unintended consequences and less efficient outcomes. It is therefore important for further review and change to be conducted and considered in a holistic and co-ordinated manner.

A comprehensive review would consider how modifications to the energy market design and regulatory framework will ensure that the impacts of climate change policies on the NEM can be accommodated efficiently and at least cost. Such a review would need to:

- address the likely nature and extent of the impact of climate change policies on the structure, economics and performance of the NEM;
- identify any elements of the NEM regulatory framework that may require incremental or more fundamental change to accommodate the impacts of climate change policies; and
- identify and assess the feasible options for change to the energy market design and regulatory framework to facilitate the integration of climate change policies with the continued efficient operation and performance of the NEM.

Building upon the congestion management reforms already being implemented, we consider that this Final Report and its important incremental recommendations will improve the CM Regime and provide important direction on the nature and scope of the priority areas for future review and reform in the context of climate change policies.

This page has been intentionally left blank

A An introduction to congestion in the NEM

A.1 Introduction

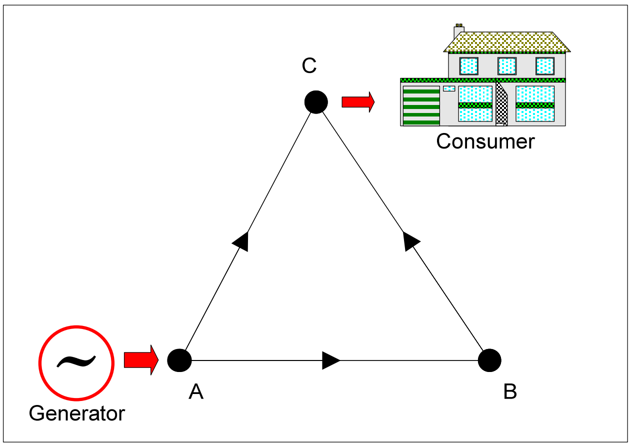
This appendix provides a simple introduction to congestion in the National Electricity Market (NEM) for readers who are new to the NEM and/or new to the topic of congestion.

A.2 What is congestion?

Electricity is transported from suppliers (generators) to consumers (retailers and large customers) along a transmission network. "Congestion" is what happens when there is a bottleneck somewhere on this network. That is, whenever a particular element on the network (e.g. a line or transformer) reaches its limit and cannot carry any more electricity than it is carrying already, it is "congested".

Electricity flows across the whole network, taking whichever paths are available. Using an example of a simple network (Figure A.1 below), power injected at point A (e.g. a power station) flows along *multiple* paths to where it is consumed at point C. This happens because power flows have to obey certain laws of physics.

Figure A.1 Flows across the network

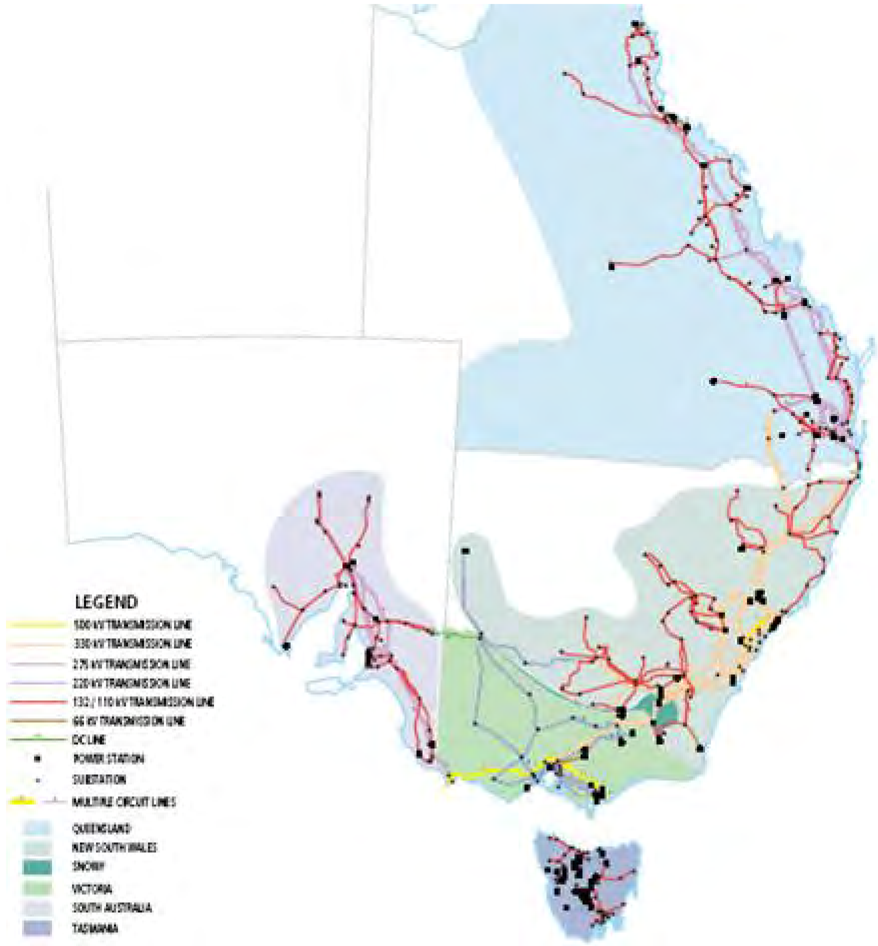


The flow of power across the network means that when a limit is reached on one part of the network, adjustments have to be made in generation and consumption across the network to ensure that the limit is not exceeded.

A congested element indicates that demand for electricity in the vicinity is equal to what the element can carry; taking into account power system security requirements. Demand must still be met, of course, so the additional electricity has to come along an alternative route and from an alternative source of supply—that is, another generator. When this situation occurs, it can affect the price at which electricity is supplied and the price that consumers must pay for it. Furthermore, congestion can make the price vary from one location to the next, whereas when there is no congestion (and assuming there are no electrical losses) the price is the same everywhere on the network.[44]

Congestion has commercial consequences and in particular creates risks for generators and retailers. It also affects the economic efficiency of the NEM as a whole.

Figure A.2 The NEM network



Data source: NEMMCO, "An introduction to Australia's national electricity market", June 2005, p. 30.

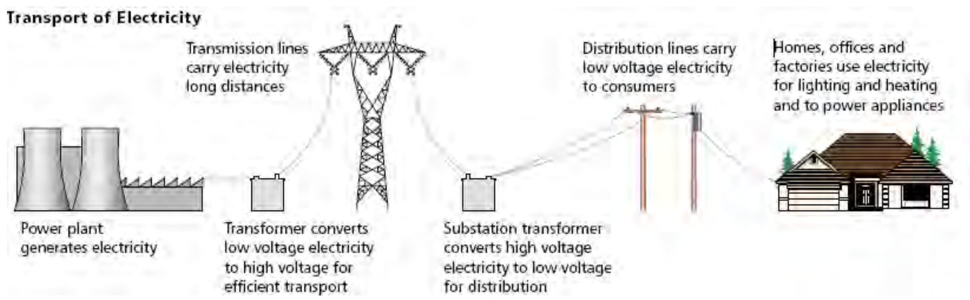
The transmission network extends from the east coast of Australia to mid-west South Australia, and from Far North Queensland all the way to Tasmania. Consumers can be supplied with electricity produced by any generator or combination of generators

44 Locational prices used to determine dispatch volumes take into account both the constraints and transmission losses. Transmission losses will cause a small variation in prices between locations even without any binding constraint on the network.

in the NEM. A consumer in Cairns, for example, can receive electricity produced by a generator in Victoria's La Trobe Valley.

This one interconnected physical network spans several distinct geographical areas. These "regions", as they are known in the NEM, are New South Wales, Queensland, Snowy[45], South Australia, Tasmania, and Victoria—almost, but not quite, identical to the States. This "one market, multiple regions" characteristic has important consequences when it comes to the impact of congestion on the NEM's financial market (discussed in subsection A.4.2).

Figure A.3 The transport of electricity: real-time supply and demand



Data source: NEMMCO, "An introduction to Australia's national electricity market", June 2005, p.3.

The network includes generation plants, transmission lines, transformers and distribution lines – the "supply" side – and consumers in homes, offices and factories – the "demand" side.

Consumer demand for electricity varies all the time; every time a light or air-conditioning unit or some other electrical device is switched on or off, demand changes. Because electricity cannot be stored, concurrently the supply of electricity varies all the time too, to keep pace with demand. So the amount of electricity being produced by generators and flowing along the network is never constant; it is always fluctuating. It is essential that supply matches demand at all times in order to maintain the quality of supply, to keep the lights on, and to maintain the integrity of the power system in the event of a security contingency (e.g. a lightning strike or plant breakdown).

Congestion is a consequence of the fact that electricity cannot be stored and therefore that supply and demand have to be kept in balance in "real-time".

A.3 Why does congestion occur?

Congestion occurs because there are physical limits to the network's ability to carry electricity. There are also security limits, designed to maintain the integrity of the

[45] The Snowy region will be abolished from 1 July 2008. See AEMC 2007, *Abolition of Snowy Region*, Final Rule Determination, 30 August 2007, Sydney.

system. If there were no limits, there would be no congestion. The ability of the network to carry electricity is known as its “transfer capability”.

Transfer capability

Transfer capability is not a simple concept. It is neither a single “amount”, nor is it fixed. Instead it depends on a complex range of factors and varies from one moment to the next, dynamically responding to changing conditions.

Broadly, we can say that at any moment in time transfer capability is governed by:

- security and reliability parameters;
- patterns of generation and demand;
- ambient weather conditions;
- the availability of transmission elements (e.g. transmission lines and transformers being in service);
- the availability of contracted Network Support and Control Services (NSCS) (e.g. reactive power capability, network loading control); and
- the technical design limitations of individual network elements—their “capacity”.

Keeping the flow of electricity within a line’s designated “capacity” is critical to the physical and operational security of the power system. Violating these limits may cause equipment damage, dangerous situations for the general public, or cascading load shedding that may ultimately lead to partial or full system shutdown. These limits can be broadly described as either “thermal” or “stability” limits:

- *Thermal limits* refer to the heating of transmission lines as more power is sent across them. The additional heat causes the lines to sag closer to the ground. The clearance above ground level must exceed certain minimum heights to ensure both public safety and power system security. Thermal limits also apply to other elements of the network, such as transformers.
- *Stability limits* refer to the need to keep the transmission system operating within design tolerances for voltage, with the ability to recover from disturbances, taking into account interaction control systems and other technical characteristics that are important to keep the power system intact. Stability limits tend to vary with the location and quantity of generation and demand, as well as with some other factors.

Congestion is therefore specific to a pattern of electrical flows, to the capability of the transmission system, and to a point in time. Congestion might emerge at a location in one five-minute dispatch interval, but disappear in the next interval. This might reflect, for example, changes in the patterns of generation or demand, or changes in transmission capabilities (e.g. as a line is brought back into service following maintenance).

In general, an enhanced ability to handle power flows means, other things being equal, a lower likelihood of network congestion occurring and hence reduced physical and financial trading risks for participants. These risks are discussed in detail in Appendix C.

In theory, congestion could be eliminated if enough money were spent on expanding the transmission network's infrastructure. However, the cost of doing this would outweigh the costs incurred from congestion itself. In this sense, congestion occurs not only because of the network's physical limitations, but also because of economic considerations of net costs and benefits. In other words, some level of congestion is in fact economically efficient.

A.4 How does congestion manifest itself?

The NEM has a physical side—the production, supply and consumption of a commodity—and a financial side—the transactions and contracts surrounding the buying and selling of that commodity. Congestion makes itself felt in both. Here we explain first how it affects the dispatch process (the physical side) and then how it affects the NEM's financial market.

A.4.1 Congestion and the dispatch process

As market and system operator, NEMMCO manages the process that determines which generators will be required to generate electricity and how much they will be required to generate in order to meet demand. This is the *dispatch process*. NEMMCO calculates dispatch every five minutes; these five-minute intervals are known as *dispatch intervals*.

In each dispatch interval NEMMCO's job is to achieve a *central dispatch objective* by calculating an optimal solution to a security-constrained dispatch problem, which contains a large number of variables, parameters, limits and constraints.

- The *central dispatch objective* is to meet demand using the "least-cost" combination of generation available.[46]
- The *variables* are the prices and quantities contained in the bids and offers submitted by market participants, as well as predefined parameters for maintaining system security and reliability.
- The *optimal solution* will therefore be to dispatch the "least-cost" combination of generation to meet demand, based on bids and offers, while remaining within the security and reliability parameters.

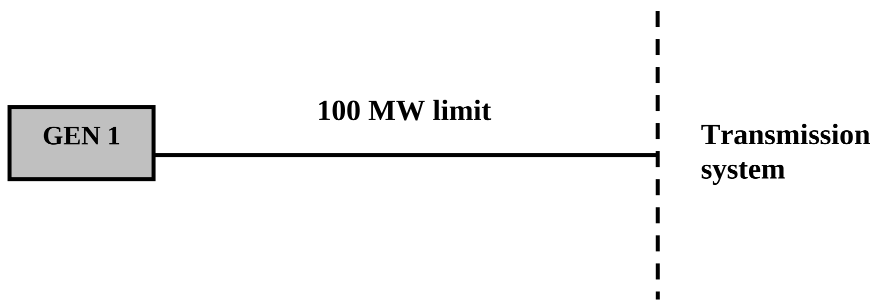
46 Clause 3.8.1 of the Rules details the responsibilities of NEMMCO regarding the central dispatch process. This Rule states that the central dispatch process should aim to maximise the value of spot market trading on the basis of dispatch bids and offers. In practice this translates into the objective to meet demand using least-cost generation.

Because the calculations are so complex and have to be performed so rapidly, NEMMCO employs a *dispatch engine* (NEMDE) to do them. NEMDE is a computer program that uses industry-standard linear programming tools to optimise dispatch.

A.4.1.1 Constraint equations and limits

The information characterising network capability and security and reliability parameters is contained in a set of "network constraint equations" within NEMDE. Each network constraint equation is a mathematical representation of the way in which different variables affect flows across particular transmission limits. A network constraint is thus a limitation imposed on the market dispatch relating to the physical capability of the transmission network in the relevant five-minute dispatch interval. The limits are derived taking into account power system security requirements. There is a separate constraint equation for each limitation imposed on the dispatch. NEMDE then solves the security-constrained dispatch problem, as described above.

To illustrate, consider the simplified example below where a generator is connected to the main interconnected transmission system by a single circuit that has a limit of 100 MW and there is no load connected between the generator and the main transmission system.



The constraint equation would be "formulated" by NEMMCO to ensure that the 100 MW limit on the line is not breached, i.e. that the output of generator GEN 1 does not exceed 100 MW. This constraint equation would therefore take the form:

GEN 1 < 100

However, NEMMCO would also need to provide for certain contingencies, such as when the transmission circuit linking GEN 1 to the main interconnected system is taken out of service for maintenance. In this contingency, the following constraint equation would be used:

GEN 1 = 0

To illustrate further, the simple example above can be extended to include load. If a load (LOAD 1) were located at the same location as GEN 1, the flow along the line with the limit of 100 MW would be determined by the generation output net of the amount of electricity consumed by LOAD 1. Hence, the constraint equation would take the form: [47]

GEN 1 – LOAD 1 < 100

In practice, the constraint equations need to reflect much more complicated sets of circumstances—for example, combinations of generation, loads and interconnector flows across multiple credible contingencies and allowing for electrical losses. There are also sets of constraint equations to ensure that system frequency is maintained within acceptable tolerances. However, the intuition behind the purpose of a network constraint equation still holds. It is a description—from the perspective of system security—of permissible combinations of variables that might influence electrical flows across a network element at a point in time.

As noted above, this “snapshot” provided by a constraint equation is dependent on the combination of transmission assets that are in service at the relevant time. The set of constraint equations reflecting a network configuration in the absence of any outages is referred to as a set of “system normal” constraints. In other instances, transmission outages might need to be scheduled to facilitate maintenance and other works on the transmission system. When this occurs, different sets of constraints need to be invoked in the dispatch process. In general, a separate constraint equation may be required for each potential contingency that materially impacts the permissible flow of electricity through a network limit, and it may sometimes be necessary for NEMMCO to build additional constraints to manage system security due to the occurrence of unusual network outage configurations. All the different constraint sets are contained in NEMMCO’s constraint library.

Form of constraint equation

In calculating the least-cost feasible dispatch, some factors can be adjusted or “controlled” through the dispatch, and other factors can be taken as given. The current convention for network constraints used in NEMDE is to include terms that can be controlled by NEMMCO through dispatch on the left hand side (LHS) of the equation, and terms that cannot be controlled by NEMMCO through the dispatch on the right hand side (RHS) of the equation. The limitation imposed on the dispatch is generally a requirement that the sum of the terms on the LHS cannot be greater than the sum of the terms on the RHS.

This is the so-called “fully co-optimised” form of constraint equation. Generator output terms and interconnector flow terms tend to appear on the LHS, while (non-dispatchable) load terms and terms relating to the limits of particular transmission elements tend to appear on the RHS.[48]

---

[47] By convention, load is expressed as a negative number, so strictly speaking the constraint equation would read: GEN 1 + LOAD 1 < 100.

[48] NEMMCO’s responsibilities regarding constraint formulation are set out in rule 3.8. Specifically, clause 3.8.10 states that NEMMCO must determine constraints on dispatch and that these must be

The extent to which increasing a particular term on the LHS utilises the limited flow allowed by a constraint, is reflected in its "coefficient" in the constraint equation. For example, a particular constraint equation may have two generator terms on the LHS, one with a coefficient of 0.3 and the other with a coefficient of 0.9. This means that the output of the generator with the 0.3 coefficient would utilise less of the allowable flow on the applicable network element(s) than the output of the generator with the 0.9 coefficient. This in turn implies that the generator with the 0.3 coefficient could produce more power without violating the constraint than could the generator with the 0.9 coefficient. A negative coefficient for a generator[49] means that its output helps relieve the constraint.

Binding constraints

Congestion can be defined as occurring when there is a binding network constraint. A network constraint is considered to "bind" when it has a direct and limiting impact on the dispatch, meaning that the dispatch (and therefore electrical flows across the network) would be different if the constraint could be relaxed. This will occur when, based on bids and offers, the lowest-cost dispatch would result in the LHS of the constraint equation exceeding the RHS.[50] The dispatch engine automatically takes this into account and in effect scales back the combined output of the LHS terms to the extent required to avoid breaching the constraint limit, so that the LHS *is equal to* the RHS. In practice, there are several thousand constraints that are taken into account by NEMMCO in the dispatch process for any given dispatch interval, and any individual term (e.g. a generator, interconnector flow, or load) might be present in a number of different constraint equations. Further, at any given time, any number of constraint equations might bind.

Relieving congestion

Importantly, inherent within NEMDE is the notion that the marginal economic value arising from an incremental increase in network capability is the same as that arising from the same incremental reduction in generation (or load) that is contributing to the congestion. In other words, there are broadly two ways in which NEMDE can relieve congestion, both of which are of equal value in reducing the costs of dispatch:

- by changing the level of variables under its control (such as generation, dispatchable loads and interconnector flows) so that the RHS limit is not violated—that is, by adjusting one or more of the LHS terms in a constraint, such as by "constraining-on" or "constraining-off" particular generators (see section A.4.2.1 below); or

---

represented in a form that can be later reviewed. Also, clause 3.8.13 specifies that NEMMCO must publish the parameters used for modelling of the constraints.

49 Or for any other term that, by convention, is measured positively. For example, an interconnector by convention will be measured positively when flowing in one direction, and negatively when flowing in the opposite direction.

50 Most constraint equations are LHS < RHS. There are some LHS > RHS and LHS = RHS also.

- by raising the RHS limit of a constraint, thereby relaxing the constraint so that it no longer binds (or binds at a higher level). In order to raise the RHS of the constraint, it is often necessary to change the value of parameters that influence the RHS limit value. Many of these limit parameters are outside the control of the dispatch engine, and to change the parameter values some external action is required by NEMMCO or a Transmission Network Service Provider (TNSP) (e.g. network switching; using NSCS as discussed in Appendix E).

Characterising congestion

Capturing network capability through constraint equations illustrates the point that congestion is what occurs when a constraint equation binds. This provides two alternative ways of characterising congestion. From one perspective, congestion can be described by identifying particular transmission limits that have been reached (and likewise identifying the associated transmission equipment or circuits that cannot accommodate increased power flow). Hence, congestion can be viewed as occurring on a particular point (or across a particular "boundary") on the transmission system. From another perspective, congestion can be viewed as the constraining influence of a network limit on the optimality of generation dispatch. For constraint equations that contain at least one interconnector flow term (in the order of 75% of constraint equations in a normal dispatch interval), the binding of the constraint would affect generation dispatch in at least two regions of the NEM. This illustrates the point that constraints can have far-reaching effects on dispatch and therefore on pricing and settlement outcomes. This is discussed further in the following sections.

Appendix E provides further explanation of the types of constraints used in the NEM.

A.4.2 Congestion and the financial market

A.4.2.1 Wholesale pricing and settlement

The price at which a generator is prepared to supply electricity is its *bid* price.[51] The price it actually receives for this electricity, if it is dispatched, is the *settlement* price. They are usually different.

Generators bid every five minutes, at each dispatch interval. Bids compete against each other in *one* market—the NEM as a whole. In contrast, settlement prices are calculated by NEMMCO, every 30 minutes (a *trading interval*), and there is a separate settlement price for *each region*.

The settlement price in each region is known as the regional reference price (RRP). The RRP is the cost (based on bids and offers) of supplying an additional unit of

[51] In the NEM, the term generator "bid" has the same meaning as generator "offer", and "rebidding" has the same meaning as "re-offering".

electricity at a particular node in the region known as the Regional Reference Node (RRN).[52] The RRNs are generally located in the major load centres in each region, such as at or near the capital city. All generators in a region receive the applicable RRP on the volume of energy for which they are dispatched across the six dispatch intervals that comprise each trading interval (ignoring losses), regardless of whether or not they are located at the RRN. Similarly, all loads in a region pay the applicable RRP for the amount of electricity they consume in the relevant trading interval (again ignoring losses).

Inter-regional price separation

When congestion occurs, it can cause differences in the marginal cost of supplying energy at different locations. To the extent this leads to different marginal costs of supply at different RRNs, the result is that RRPs diverge.[53] This is typically reflected in cheaper generation being "backed off" in low-priced regions as a result of a constraint binding, and more expensive generation being dispatched in high-priced regions.

As in other markets, these inter-regional price differences play an important signalling role in the NEM. In the short-term, they provide signals to generators in higher-priced regions to produce more and to loads in higher-priced regions to consume less. In the longer term, price differences can encourage efficient decisions by market participants concerning when and where to invest in generation and load assets.

Inter-regional price differences also create financial trading risks for participants. If a generator in one region contracts with a party in another region (and references the contract to that other region), the generator will have to manage the risk that the price in its region may differ from the price in the other party's region. The risk of this price difference occurring is called "basis risk". Basis risk and the way it is presently managed in the NEM is discussed below in section A.4.2.2. Appendix C also provides more detail.

Intra-regional "mis-pricing"

In the NEM's regional pricing and settlement structure, congestion can also cause differences in the marginal cost of supply within a region, i.e. between the RRN and other nodes in the region.[54] The marginal cost of supply at each node other than the RRN is referred to as the local or "pseudo" nodal price, and this is calculated as a by-

---

52 In order to calculate RRPs, each constraint must be "correctly orientated" towards the relevant RRN. Constraint equations are correctly orientated if and only if there are no terms involving the RRN in any region in any constraint equation.

53 Price divergences can also be caused by electrical losses and frequency control effects, in the absence of any binding network constraints, but the focus throughout this report is on price divergences caused by network congestion.

54 Appendix C explains how the extent of mis-pricing for any particular point on the network, at any particular point in time, can be calculated.

product of the dispatch process. In other words, participants are effectively dispatched on the basis of a comparison between their bid or offer price and their local nodal price. In general, if their bid or offer price is less than their local nodal price, they will be dispatched to the corresponding volume; if their bid or offer price is greater than their local nodal price, they will not be dispatched. There are exceptions, however (see the discussion about dispatch risk below).

To the extent that congestion causes divergences between the RRP and local nodal prices in the NEM, this impact is not reflected in differences in the prices paid or received by participants located at those other nodes in the region. As noted above, all generators (and loads) within a region receive (and pay) the same price (the RRP) for the energy they are dispatched to produce (and consume) within a trading interval regardless of whether their implied local nodal price is the same as their RRP. This disjunction between the implied nodal prices yielded by the dispatch process and the RRPs used for settlement is commonly referred to as "mis-pricing". Mis-pricing can create risks for participants and promote behaviours that reduce economic efficiency. This is discussed further in Appendix C.

Dispatch risk

Mis-pricing gives rise to physical or "dispatch" risk for generators, because it means that generators may not be dispatched even if they are willing to supply power at or below the prevailing RRP. This could lead to generators having to make "unfunded difference payments" on their contracts. Alternatively, generators could be dispatched even if they are not willing to supply electricity at or below the RRP.

A generator can be required to generate a volume of output that is different to the volume it would wish to generate given the prevailing settlement price (i.e. the RRP). In such situations, generators are referred to as being "constrained-on" or "constrained-off":

- a generator is said to be "constrained-on" when it is dispatched for a quantity that is *greater* than the amount it is willing to produce at the (settlement) price it is paid;

- a generator is said to be "constrained-off" when it is dispatched for a quantity that is *less* than the amount it is willing to produce at the (settlement) price it is paid.

The main risk for a constrained-on generator is that it incurs a loss on the additional output it is required to produce. This might be a *direct* loss, such as where the constrained-on generator is paid less than its avoidable fuel cost of production. Or it might be an *indirect* loss, such as where an energy-constrained generator is required to forego the opportunity to generate at times when it is more profitable.

The main risk for a constrained-off generator is that it is prevented from earning the RRP on the volume of output it would wish to generate at that price. To the extent such a generator is financially contracted, it may be required to make cash difference payments on its contracts that are not funded by its revenues in the spot market. If this occurs at times of very high prices, the cost can be substantial. However, even if a generator is not contracted, being constrained-off implies that it has foregone revenues that it could otherwise have earned if it were not constrained-off.

When a generator is constrained-on, it is said to be "negatively mis-priced", because its settlement price (the RRP) is less than the nodal price used to determine its dispatch volume. Conversely, a constrained-off generator is said to be "positively mis-priced", because its settlement price (the RRP) is greater than the nodal price used to determine its dispatch volume.

In general, volume or dispatch risk caused by mis-pricing can result in:

- constrained-on generators being incentivised to make offers up to the maximum price of $10 000/MWh (or bidding unavailable[55]); and
- constrained-off generators being incentivised to make offers down to the market floor price of -$1 000/MWh (or bidding inflexible).[56]

These sorts of behaviour are referred to as "dis-orderly" bidding. Clearly, such offer prices would not reflect generators' underlying resource costs of production. In an environment of such "dis-orderly bidding", the economic efficiency properties of the bid-based merit-order dispatch approach used in the NEM may be undermined. For example, a generator with a resource cost of $30/MWh that seeks to avoid being constrained-on by offering its capacity at $10 000/MWh may cause the dispatch of a generator with a resource cost of $50/MWh. This leads to a short-term loss of economic welfare to the market of $20/MWh multiplied by the output of the higher-cost generator. Similarly, a generator with a resource cost of $100/MWh may avoid being constrained-off by offering its capacity at -$1 000/MWh, thereby displacing a generator with a resource cost of $30/MWh. This behaviour would cause a welfare loss of $70/MWh over the displaced output.

To the extent that generators cannot manage their dispatch risks by bidding in a dis-orderly manner, they may be inclined to reduce their overall level of financial contracting and/or increase contract premiums. Given that a large proportion (if not all) of most generators' contracts are made with counterparties within their own region (i.e. settled at their local RRP), this could lead to reduced contract competition within that region. The result may be higher retail prices and reduced consumption, reducing allocative efficiency.

In the longer term, dispatch risk caused by mis-pricing may distort generators' locational investment decisions under the NEM's regional wholesale pricing and settlement arrangements. For example, to the extent a proponent of a generation project believes it can manage dispatch risk through dis-orderly bidding, it may be tempted to invest in a relatively high-cost plant in a congested part of the network. Alternatively, if dis-orderly bidding is unlikely to enable a prospective generator to

---

55 "Bidding unavailable" means a generator is unable to be dispatched (supply output) to meet demand.

56 The extent to which this extreme "dis-orderly" bidding behaviour will occur depends on the extent to which a generator's offer price affects the RRP that it is paid. The smaller the influence of a generator's bid on the RRP, the less inhibited it will be about, say, bidding at -$1 000/MWh.

manage dispatch risk, then even an efficient new entrant may be deterred from investing. Either way, dynamic efficiency would be compromised.

For these reasons, the extent of mis-pricing may provide a useful indication of the potential productive and dynamic costs of congestion. Estimates of the incidence and materiality of congestion in the NEM are discussed in Appendix B.

Importantly, a key implication of both basis risk and dispatch risk is a reduction in generators' willingness to contract. In the case of basis risk, the unwillingness largely relates to inter-regional contracting. In the case of dispatch risk, the unwillingness largely relates to intra-regional contracting.

A.4.2.2 Financial trading

Derivative trading

The NEM is a "gross pool" market, in that virtually all electricity must be bought and sold through the wholesale spot market operated by NEMMCO.[57] Therefore, participants tend not to enter contracts for the physical delivery or receipt of power. However, participants do enter financial contracts in order to hedge their exposures to volatile wholesale spot prices. Financial contracts are used to set or limit the price ultimately paid for and received for wholesale electricity in the NEM by retailers and generators, respectively.

Generators are exposed to the risk of *low* spot prices, so they need to manage cash flows to meet financial obligations relating to operational and maintenance costs, fuel costs and financial charges. Retailers are exposed to the risk of *high* spot prices, so they need to manage their gross margin, i.e. the difference between the price at which they purchase energy and the price they charge customers for the energy they consume. These risks are largely inverse, creating a potential for generators and retailers to hedge their spot price exposures by entering financial contracts with one another.

For example, swap contracts allow participants to agree on a fixed "strike price" that is based on the RRP in a particular region. Where the RRP in a trading interval is *above* the strike price, one counterparty (typically the generator) will make "difference payments" to the other counterparty (typically the retailer or large customer). Where the RRP is *below* the strike price, the retailer (typically) will make difference payments to the generator. As in other financial markets, many other types of contracts exist, such as caps and collars.

There are two options for entering into contracts in the NEM:

- *over the counter (OTC) contracts* involve entering into a bilateral agreement with a known counterparty. OTC transactions can either be negotiated directly with

57 The Rules provide certain exemptions, largely related to on-site generation.

other market participants (retailers or generators), or arranged via a broker who offers contracts with standard terms and conditions; and

- *exchange traded contracts* involve entering into a standardised contract with an exchange, such as the Sydney Futures Exchange (SFE). The exchange stands between the buyers and the sellers of futures contracts, so that the buyers and sellers do not trade directly with each other.

The vast majority of trading in electricity derivatives by volume occurs using OTC contracts rather than exchange traded contracts.[58]

Basis risk

Where participants in the NEM have entered financial contracts that are settled against RRPs in other regions, they are vulnerable to differences between their local RRP and the RRP at which those contracts are settled. These differences in RRPs are caused by differences in the marginal cost of supply at different RRNs. This gives rise to financial trading or basis risk. These trading risks largely derive from participants' entry into financial derivative contracts.

For example, a generator in Victoria is settled in the spot market at the Victorian RRP. However, if the generator has entered into a swap contract with a retailer in NSW and this contract is settled at the NSW RRP, the generator faces a risk that Victorian and NSW RRPs could diverge due to binding constraints. If the NSW RRP rises above the Victorian RRP, the generator could be in a position where it has to make difference payments (equal to the difference between the NSW RRP and the strike price of the swap multiplied by the contract quantity) to the NSW retailer, even though the generator has only received the (lower) Victorian RRP on its actual output.

The extent of such inter-regional basis risk depends on the frequency of binding constraints that affect flows between regions and the divergence between regional prices at these times. However, to the extent it arises, basis risk may deter participants from entering contracts with counterparties in other regions. Ultimately, because most retailers typically seek to be fully hedged against spot price volatility, reduced contract competitiveness could be expected to lead to higher contract premiums and higher retail prices. This, in turn, could lead to lower electricity consumption than would otherwise be the case, harming allocative efficiency.

Reduced contract competitiveness could also reduce dynamic efficiency in the longer term by distorting generation and load investment incentives in terms of the timing and location of new plant. For example, higher retail electricity prices could deter or delay investment in new load projects and could encourage generation proponents to invest before it is efficient to do so.

58 However, between 2002/03 and 2006/07, there has been a significant increase in the total volume of exchange traded contracts and the relative decline in the proportion of broker traded OTC contracts. See PriceWaterhouseCoopers (2006), "New Perspectives on Liquidity in the Financial Contracts Electricity Market", PWC, Sydney, November.

Tools are available to enable participants to hedge the inter-regional price differentials caused by congestion. When RRPs diverge, inter-regional flows create Inter-regional Settlement Residue (IRSR) funds, which are equal to the difference between the RRPs of the destination (i.e. importing) and source (i.e. exporting) regions, multiplied by the volume of flow and time duration.[59] Settlements of inter-regional power flows are made from the IRSR funds. Shares to a proportion of the IRSR fund for each directional interconnector are regularly sold at Settlement Residue Auctions (SRAs). Participants can acquire IRSR units to hedge the basis risk of contracts referenced to a different region's RRP.

However, as discussed in Appendix C, IRSR units do not typically provide a firm (i.e. reliable) hedge against contract exposures arising as a result of inter-regional price differentials. To the extent that IRSR units provide an imperfect hedge for basis risk, the actual or potential presence of congestion may deter participants from contracting across regional boundaries and/or demanding higher contract premiums.

An alternative means of managing basis risk is for participants to enter bilateral contracts with a participant in another region. This is equivalent to participants "backing out" of their inter-regional basis risk exposures.

A.5 Summary: the consequences of congestion

In summary, congestion has direct and indirect as well as short- and long-term consequences.

A.5.1 Direct consequences

Higher prices

The most direct impact of congestion is that more expensive generators have to be dispatched to meet demand than would otherwise be the case. This increases the price of electricity for both wholesale and retail customers.

System security issues

Congestion increases the likelihood of system security and supply reliability problems, which then have to be resolved by NEMMCO (the system and market operator).

---

59 Clause 3.6.5 defines settlement residues due to network losses and constraints. This includes the process for settlement residue distribution and recovery. Rule 3.18 identifies the Settlement Residue Auction as the process by which NEMMCO auctions off rights to these residues, which are allocated to regulated directional interconnectors in the NEM. This rule also sets out the concepts, general auction rules, persons eligible to participate in the auction, auction proceeds and fees and the responsibilities of the Settlement Residue Auction Committee.

A.5.1.1 Indirect consequences

Trading risks for participants

Congestion increases the trading risks—both physical (dispatch risk) and financial (basis risk)—faced by market participants. In response, participants engage in strategies and activities to manage these risks. This leads to participant behaviours that reduce the economic efficiency of the NEM in both the short- and long- terms. For example, "dis-orderly bidding" by generators compromises productive efficiency.

Uncertainty for investors

Congestion can weaken economic signals that support efficient investment decisions by generators and large industrial and commercial users about where to invest in transmission and/or generation. This is a longer-term effect of congestion, which compromises dynamic efficiency in the NEM.

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.

---

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.

---

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

---

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.

---

[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]

---

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,

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.

---

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.

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

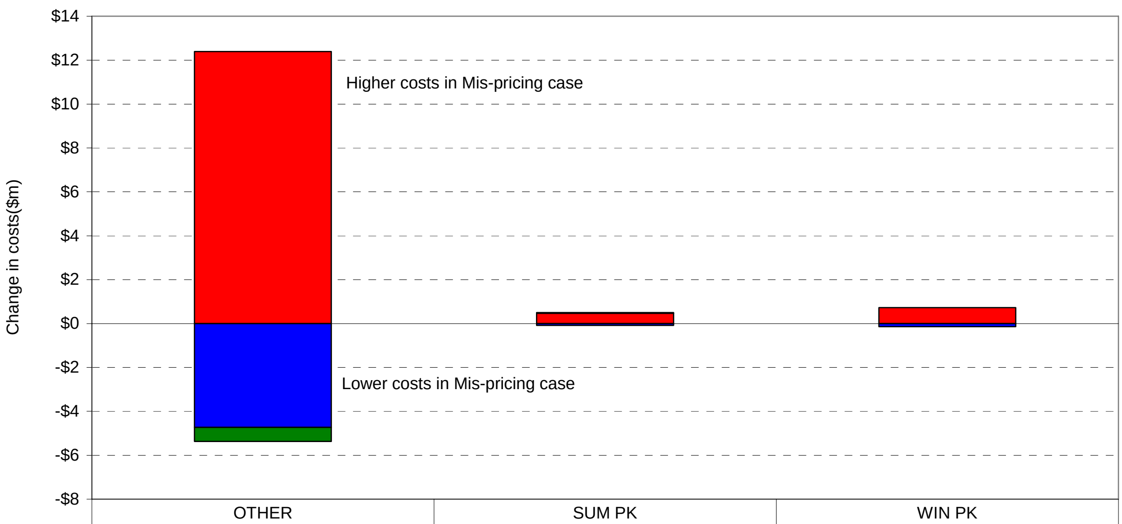
96 For example, if negative settlement residues of $X arose on DirectLink and positive residues of $Y arose on QNI then DirectLink would not be clamped if X<Y and would be clamped if X > Y + threshold.

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

Time of year

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)

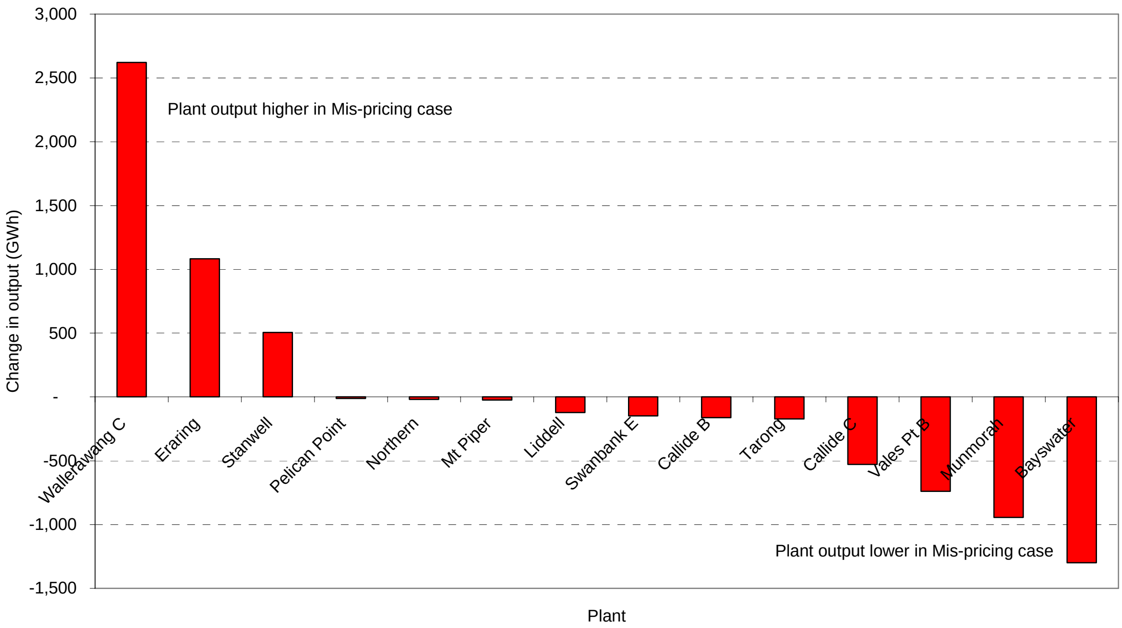
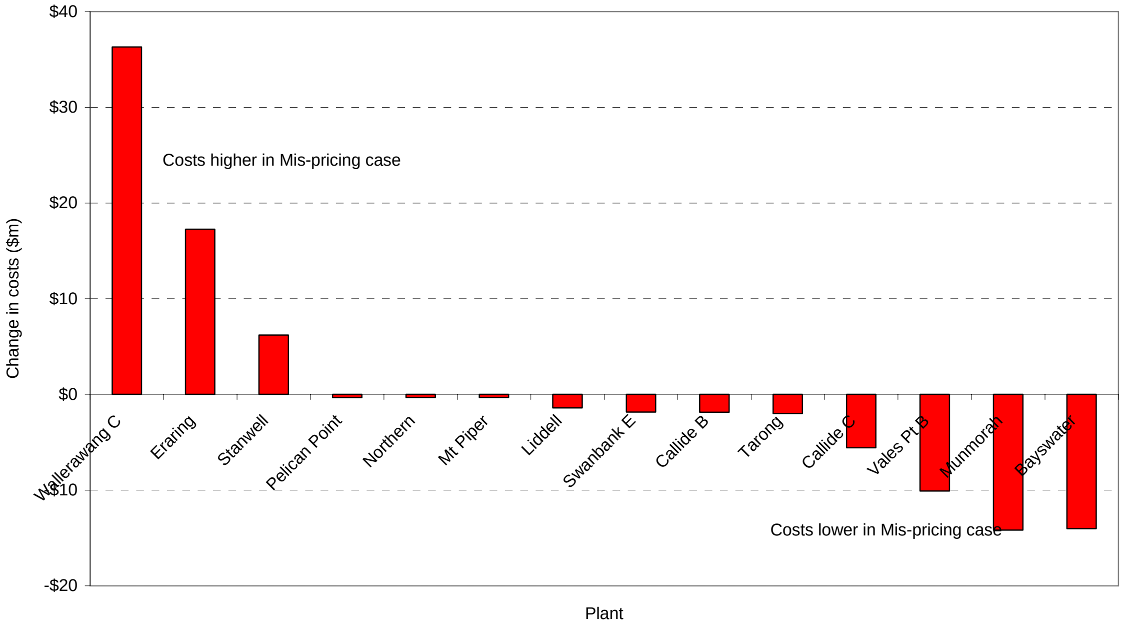


Figure B.3 Change production costs by plant type ($m)



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,

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.

---

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

---

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.

[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.

This page has been intentionally left blank

C Assessment of Congestion Management Regime elements

This appendix discusses in more detail the Congestion Management (CM) Regime elements and our recommendations, discussed in chapter 3 of the Final Report:

- Section C.1 describes in more detail the nature of locational signals in the CM Regime;
- Section C.2 discusses the dispatch arrangements;
- Section C.3 discusses transmission access, pricing, incentives and investment planning;
- Section C.4 discusses risk management instruments;
- Section C.5 discusses wholesale pricing and settlement arrangements; and
- Section C.6 discusses the role of information.

In addition, this appendix also notes comments from Draft Report submissions that relate to our interpretation of the Terms of Reference and our analytical evidence base. These are summarised in sections C.7 and C.8.

C.1 The nature of location signals in the CM Regime

In the NEM today, the CM Regime provides a range of locational signals to market participants:

- *Price separation between regions*—congestion can lead to regional differences in the cost of supplying demand. In the NEM market design physical network constraints reveal themselves in the market through differences in the RRPs. Systematic differences in RRPs provide important signals as to where additional generation capacity might be most valued.

- *The prospect of changes to pricing regions*—the signals provided to investors through wholesale market pricing are also conditioned by the possibility of region boundaries being changed. In 2007 we amended the Rules to put in place a new process for changing region boundaries.[118] A case for region change must now be based on economic evidence of an enduring and material congestion problem. This means that investors need to factor in the possibility that congestion points which are not currently priced in the NEM region model, including new congestion points created by new investment, may be priced in the future as a result of a region boundary charge.

- *Transmission losses*—generators that are closer to centres of demand will, other things being equal, be cheaper (and therefore more competitive) than generators further away from demand. This is because of losses on the transmission system. Transmission losses are reflected in the market through the application of loss factors. There is a static loss factor for each point within a region (reflecting an annual average level of losses at that point), and there are dynamic loss factors which are calculated every five minutes for flows between regions.

- *Dispatch risk*—generators at different locations face different probabilities of not being dispatched due to constraints on the network. Other things being equal, a generator located at an uncongested point on the network will be more competitive than a generator located at a congested point on the network. This might reveal itself in an ability to offer greater volumes in the contract market at a more competitive price. It might also reveal itself in the form of a higher discount rate being applied by investors in considering investment options with higher dispatch risk.

- *Connection charges*—generators pay a "shallow" charge for the connection service provided by a TNSP. This charge reflects the cost of the assets required to connect the generator to the main interconnected network. Additionally, the Rules provide for generators to negotiate different levels of connection service. This may involve a generator agreeing to fund deeper reinforcement work on the transmission network in return for reduced dispatch risk. It may also involve a generator recouping some of the costs of deeper reinforcement work if new generators subsequently connect. These costs are forms of locational signal.

---

118 This new process commences on 1 July 2008.

- *Regulated transmission investment*—TNSPs have obligations and financial incentives to invest efficiently in their networks. The Regulatory Test requires that network investment must be justified economically on the basis of meeting standards for reliability, or on the basis of delivering net market benefits. Any investment required by a particular generator over and above this must be funded by the generator itself (or the generator must accept the consequences in terms of dispatch risk). This is an important form of locational signal. The planned reforms to the Regulatory Test and the establishment of a National Transmission Planner (NTP), as part of the implementation of national transmission planning arrangements, will improve the effectiveness of this form of signal.

- *Fuel access and transport costs*—other things being equal, a generator that is located close to its fuel source will be more competitive than a generator that incurs significant costs in transporting its fuel to its generating station. The relative cost of transporting fuel, as compared to locating at the fuel source and transmitting the generated electricity greater distances, is another form of location signal. Clearly, this is more relevant to some generating technologies (e.g. gas) than others (e.g. wind).

The locational signals provided through the CM Regime, including the prospective reforms to the Regulatory Test and the establishment of a NTP, play an important role in influencing decision-making by market participants. In addition, these factors may indirectly or directly influence investment decisions, for example whether to finance a project and, if so, what project and at what cost. It is how these signals combine, rather than the form or strength of a particular signal on its own, that matters when assessing their impact on the efficiency of outcomes for consumers.

As an example of how these factors inform an investment decision, Babcock and Brown Power provided information on its decision to invest in the 640 MW Uranquinty project in New South Wales.[119]

In the early stages of Uranquinty's development, Babcock and Brown stated there was a view published that the plant would not increase New South Wales' generating capacity, and would increase network congestion. Babcock and Brown commented that while this view was at odds with the project proponents, and was later retracted, once the debt and equity capital markets became aware of it, they required further investigation into the claims.

The independent analysis undertaken by both the debt capital and equity capital proponents confirmed three key points:

- Uranquinty adds to the reliability of power supplies in New South Wales and with high northward flows, "improves transient stability quite significantly"'

- increasing Snowy-to-NSW transmission capacity by 500 MW has a negligible effect on the run time of the Uranquinty plant (i.e. less than 30 minutes per

119 Babcock and Brown Power, Draft Report submission, pp.1-2.

annum), therefore indicating that the plant is not significantly impacted by existing line limits; and

- network constraints would be "very rare".

Babcock and Brown Power presented that the economics of this power project were:

> "driven heavily by fuel and transmission connection, which then manifest[ed] themselves in output quantities and prevailing regional prices."[120]

If the project was likely to face network constraints, therefore affecting the last two key variables, then the overall projected revenues would have been downgraded accordingly. This would have limited the level of debt the project could raise and carry. This could deem the project uneconomic.

This project provides a recent case study on how these existing investment locational signals inform investment decisions in the NEM today.

[120] Babcock and Brown Power, Draft Report submission, p.2.

C.2 Dispatch

C.2.1 Background

This Review has examined the transparency and predictability of the central dispatch process. More information and a greater level of certainty about how dispatch operates will assist generators and large customers in making decisions on bids and offers to manage the risks associated with congestion. Clear rules and guidelines will also give NEMMCO a more structured framework under which to operate.

We considered the following specific issues:

- the formulation, development and implementation of constraint equations
- the arrangements according to which NEMMCO may physically intervene in dispatch to manage the accumulation of negative settlement residues
- the availability of information on planned network events, to help market participants predict the emergence and impact of congestion and manage the consequent risks.

C.2.2 Constraint equations: formulation, development, implementation

C.2.2.1 Background

The physical limits of the network are represented mathematically in NEMDE (NEMMCO's linear program dispatch engine) as constraint equations. During the dispatch process, NEMMCO uses these constraint equations to define the set or permissible solutions. For example, increased output by a particular generator may increase (or decrease) flows across a certain transmission element. As changes occur in the physical network, NEMMCO adjusts the constraint equations to reflect those changes. This adjustment could be changing a limit or replacing a constraint equation. How these constraint equations are formulated directly affects the way in which generation and load are dispatched, and therefore has significant commercial consequences.

For this reason it is important that NEMMCO is consistent and transparent in how it formulates constraint equations. Market participants also need to understand how NEMMCO goes about developing and implementing new constraint equations and modifying existing ones, if they are to understand the commercial implications of security-constrained dispatch.

C.2.2.2 Discussion

Formalising constraint formulation

Evolution of the fully co-optimised constraint formulation

Constraint equations have a LHS and a RHS. Terms on the LHS can be directly controlled by NEMMCO; terms on the RHS cannot.

Prior to July 2004, NEMMCO treated interconnector terms differently from generator output terms. For example, in some cases it applied an "option 1" formulation, in which interconnector flow terms are placed on the RHS of a constraint equation, i.e. they are taken as given in optimising the dispatch.

From July 2004, however, NEMMCO began to adopt a "fully co-optimised direct representation constraint formulation" (hereafter: fully co-optimised constraint formulation) for all constraint equations. In this formulation, all terms are placed on the LHS and therefore may be directly controlled by NEMDE.[121] Having direct control of as many of the variables in the dispatch process as possible allows NEMMCO to achieve a more optimal dispatch of all possible control variables and thereby improves NEMMCO's ability to manage system security. This more efficient use of the network improves NEMMCO's ability to maintain supply reliability and can lead to a lower dispatch cost.

An MCE policy position endorsing NEMMCO's use of fully co-optimised constraint formulation triggered NEMMCO's formal adoption of this constraint form. The MCE articulated this position in its *Statement on NEM Electricity Transmission* in May 2005. The MCE's decision to endorse the fully co-optimised constraint formulation was based on advice from its consultants Charles River Associates (CRA) who, after a lengthy consultation process, recommended that:

> "On the basis that no change to the current economic objective of the five-minute spot market dispatch process is made, NEMMCO should apply the Direct Physical Representation (DPR, or "fully optimised") form of constraints (Option 4/5) to all network constraints. The Code should be amended to confirm this."[122]

The MCE also endorsed this constraint formulation in the Terms of Reference for this Review.[123]

Formalising constraint formulation in the Rules

NEMMCO has reformulated and now uses fully co-optimised system normal constraint equations in NEMDE.[124] The ability under the Rules for NEMMCO to

---

[121] There are a few exceptions and these are discussed below.

[122] Charles River Associates (CRA), *NEM Transmission Region Boundary Structure*, pp.26.

[123] MCE, CMR Terms of Reference, p.3.

formulate fully co-optimised constraint equations is currently contained in the time-limited derogation in Part 8 of Chapter 8A of the Rules. This derogation, originally authorised on 28 April 2004[125], enables NEMMCO to "determine and represent constraint equations in dispatch which may result from limitations on both intra-regional and inter-regional flows."

Given that the fully co-optimised constraint formulation is endorsed by the MCE and most market participants support formalising the requirement that NEMMCO uses this formulation, we decided that is it now appropriate to formalise in the Rules this constraint formulation into Chapter 3 of the Rules. This was one of our recommendations in the Draft Report.

Submissions to the Draft Report supported this recommendation.[126] NEMMCO supported the recommendation on the basis that it would ensure effective control of power flows. Macquarie Generation, however, was critical, expressing the view that we needed to do further work to define adequately the term "fully co-optimised network constraint formulation". It considered that the Rules should define the constraint formulation in terms of achieving an "objective", and that NEMMCO could only alter a constraint equation if it met this set objective. Macquarie Generation supported more transparency and accountability on the part of NEMMCO in the constraint setting process.[127]

These concerns are principally addressed through the requirement for NEMMCO to develop and apply with "Network Constraint Formulation Guidelines". The guidelines are discussed in a subsequent section C.2.2. In addition, when we consulted on the proposed Rule changes that would implement this recommendation, we did not receive any substantive comments on the definition of "fully co-optimised network constraint formulation". Therefore, we consider that between the Network Constraint Formulation Guidelines and the proposed definition and changes to the Rules to implement this recommendation, we have accounted for and addressed Macquarie Generation's concerns.

"Hardwiring" the form of the constraint formulation into the Rules provides flexibility for future change, but only through approval by the AEMC of a Rule change proposal. This will ensure that any proposed change is consulted on fully and assessed against the National Electricity Objective.

An alternative constraint formulation for exceptional circumstances

In some exceptional circumstances NEMMCO currently uses an "alternative constraint formulation" (or ACF) that is not fully co-optimised. NEMMCO uses

---

124 All system normal constraints are now fully co-optimised. NEMMCO will convert outage constraints and infrequently used constraints as required.

125 For a history of the Part 8 of Chapter 8A derogation, see section 4 of the AEMC Decision Report, *Determination by the AEMC on the expiry date of the participant derogation in Part 8 of Chapter 8A of the National Electricity Rules - Network Constraint Formulation*, 3 May 2007. Available: www.aemc.gov.au.

126 CS Energy, Draft Report submission, p.3, Origin Energy, Draft Report submission, p.1, EUAA ,Draft Report submission, p.25, Hydro Tasmania, Draft Report submission, p.3.

127 Macquarie Generation, Draft Report submission, pp.4-7.

ACFs where they will deliver greater security in the power system compared to using a fully co-optimised constraint formulation. NEMMCO currently identifies the general exceptions in its "Network and FCAS constraint formulation" document.[128]

While it is important for the system operator to have a level of flexibility in the Rules to use an ACF, it is also important for market participants to have certainty around what constraint formulation NEMMCO will use in dispatch. Consequently, in our Draft Report recommendation on constraint formulation, we suggested that the new Chapter 3 of the Rules should include a provision allowing NEMMCO to implement an ACF but only in exceptional circumstances. In the Draft Report, we defined exceptional circumstances as circumstances in which "NEMMCO reasonably determines that an ACF is necessary to meet system security requirements or to manage negative settlement residues provided that NEMMCO's use of an alternative constraint formulation is consistent with [certain] guidelines".

NEMMCO clarified in its Draft Report submission that it did not require an ACF to manage negative settlement residues. As such, the exceptional circumstances to use an ACF no longer include negative settlement residue management. NEMMCO's process to manage these residues, however, is discussed below in section C.2.3.

NEMMCO also confirmed that an ACF was consistent with its Network and FCAS constraint formulation paper.[129] Other submissions to the Draft Report made it clear that they wanted NEMMCO's use of an ACF to be transparent and predictable.[130]

To help ensure that the deployment of an ACF is transparent and predictable to the market, we recommended in the Draft Report introducing "guidelines" for NEMMCO to follow. We now include in the recommended new Rule a requirement that NEMMCO must develop and comply with guidelines (Network Constraint Formulation Guidelines)that detail the circumstances in which an ACF is needed to meet system security requirements and describe what ACFs may be used. (These guidelines are discussed further in section C.2.2 below.)

In summary, NEMMCO may only use an ACF if it is during circumstances that it has identified in the constraint guidelines and will not adversely affect power system security or supply reliability. This will provide clarity and transparency to the specific circumstances under which NEMMCO will use an ACF.

Guidelines for formulating, developing (and modifying) and using constraint equations

The constraint equations that NEMMCO uses in the dispatch process manage a range of variables: network limitations (under both system normal and outage conditions), ancillary service requirements, generator non-conformance, network security

---

[128] NEMMCO, "Network and FCAS constraint formulation", version 8, 4 July 2005. Available: http://www.nemmco.com.au/dispatchandpricing/170-0030.htm.

[129] NEMMCO Draft Report submission, p.4.

[130] CS Energy, Draft Report submission, p.3, Hydro Tasmania, Draft Report submission, p.3.

violations, generator ramp rates, interconnector rates of change, and other discretionary events.

There are methodologies and processes associated with constraint equation formulation and use. First, there is a methodology for formulating a constraint. This can include deciding which side of the constraint equation a particular term should go, e.g. LHS or RHS, or converting a TNSP provided limit equation into a constraint equation.

Then there is the process of developing or modifying the constraint equations. This includes sourcing information from TNSPs, generators, and other market participants and then translating that information into a constraint equation. The process of updating a constraint equation to reflect a network augmentation or a new connecting generator or load, or perhaps developing a new constraint to account for a new network element can involve changing a constraint's limit or the coefficients. At the end of this process the new or modified constraint is included in NEMMCO's constraint library, and the market is notified.

The current process for developing or modifying constraint equations involves a series of steps such as the following:

1. A TNSP notifies NEMMCO of a change in transfer limits resulting from a change to the physical network or assets connecting to its network.

2. NEMMCO carries out a due diligence assessment of stability-related limits.

3. NEMMCO develops or modifies the constraint equation(s).

4. NEMMCO tests the constraint equation(s).

5. NEMMCO then includes the new or modified constraint equation(s) in the constraint library, ready for use in dispatch when required.

Another process relates to how constraint equations are utilised. This includes determining when and how constraint sets, which can include a number of constraint equations, are invoked[131] and revoked[132].

These methodologies and processes are not currently formalised under the Rules. Instead, NEMMCO publishes information related to these processes and the associated methodologies in various documents. The Rules do not require NEMMCO to follow or apply these documents. This means the requirements to keep participants informed during the processes are also quite limited.

We suggested in our Directions Paper that more information on the methodologies and processes NEMMCO uses to formulate, develop, and use constraint equations may help participants better understand how constraints are likely to affect dispatch.

131 When a constraint set is invoked, the constraint equations contained in the set are active in the market systems, and therefore can affect dispatch.

132 When a constraint set is revoked, the constraint equations contained in the set are inactive in the market system and will no longer affect dispatch.

Through bilateral discussions, a number of participants have expressed concern about the uncertainty and lack of understanding around the development and implementation of constraint equations, potentially exacerbating trading risks. Some suggested that constraint formulation and development is not as transparent as it should be, and that NEMMCO should consult on the specification of each constraint equation.

Although we felt that specific consultation on each individual constraint equation would be impracticable, we did recommend in the Draft Report that NEMMCO should formulate, develop, and use constraint equations in accordance with published "constraint guidelines". These guidelines would give market participants sufficient information to understand NEMMCO's methodology for formulating constraint equations, its process for developing them, and its process for using them. This, in turn, will assist participants to assess the impact of constraints on dispatch and pricing.[133] We recommended that NEMMCO should develop these guidelines in consultation with stakeholders, and once published should be obliged to comply with them. NEMMCO is to amend these guidelines as necessary.

In submissions to the Draft Report, most participants supported this recommendation. NEMMCO also supported the recommendation and even identified currently available information that it could use to meet the requirements of such guidelines.[134] EUAA added that the guidelines should contain worked examples to illustrate the application of constraint equations.[135]

Some submissions, also called for an independent review and audit of existing NEMMCO processes pertaining to the current constraint equations and the constraint formulation process.[136] The NGF, Macquarie Generation, and InterGen all considered that a review would improve the constraint formulation and implementation processes and increase market participants' confidence in the dispatch process.

In our view, it is not necessary to have an independent review or audit of NEMMCO's existing practices given that the new guidelines will substantially increase transparency and the existing processes to quality assure NEMMCO process more generally. Our Constraints Draft Rule, which would implement our recommendations related to constraint formulation and guidelines, requires NEMMCO to publish and apply its methodology and processes going forward.[137] This will make it easier for participants to understand what and why constraint

---

133 Clearly, there is some overlap between the provision of generic information about methodology and process and the provision of specific information about when, how and why NEMMCO invokes and revokes particular constraints. The constraint guidelines focus on the generic formulation, development and use of constraints while the specific information about what particular constraint is used because of a certain network outage is discussed in section C.6.

134 NEMMCO, Draft Report submission, p.5.

135 EUAA, Draft Report submission, p.26.

136 Macquarie Generation, Draft Report submission, p.8; NGF, Draft Report submission, p.8; InterGen, Draft Report submission, p.1.

137 The Constraints Draft Rule is in Appendix G. Section C.2.2.3 discusses the components of it in more detail.

equations have been constructed in the way they have. It will also make it easier to review whether there are any inconsistencies in NEMMCO's application of its methodology and processes. We were not persuaded that this formal level of intervention is required.

C.2.2.3 Final recommendations and implementation

Formalising constraint formulation

We recommend that NEMMCO be obliged to use the fully co-optimised direct representation constraint formulation wherever practicable. We also recommend that NEMMCO be allowed to use an alternative constraint formulation in exceptional circumstances that are pre-defined in its Network Constraint Formulation Guidelines.

The Constraints Draft Rule will require NEMMCO to publish in its constraint guidelines the process it will use for invoking and revoking constraint equations, both fully co-optimised and ACF. This includes the circumstances under which it will use fully co-optimised and ACF and how it will inform the market participant of the process. This information will further support each participant's ability to predict and respond to changes in dispatch related to changes in the constraint equations used in the market system.

The Constraints Draft Rule will also require NEMMCO to develop, publish and comply with Network Constraint Formulation Guidelines that explain the methodology and processes NEMMCO uses to develop, formulate and implement both fully co-optimised and alternative constraint formulations. These Guidelines are to include NEMMCO's policy for managing the accumulation of negative settlement residues, as well as an account of *how* it manages them, including its intervention trigger if required. NEMMCO is to develop these guidelines in accordance with the Rules consultation procedures.

Given the potentially significant commercial impacts of the way in which constraint equations are formulated, developed and used, we believe these matters should be subject to a high degree of transparency and predictability. In addition, greater information about which constraint equations will be used in dispatch will improve participant decision making.

Implementation

Our proposal for implementing this recommendation is contained in the *Draft National Electricity Amendment (Fully Co-optimised and Alternative Constraint Formulations) Rule 2008* (the Constraints Draft Rule), published in Appendix G. The provisions for constraint formulation previously included in Part 8 of Chapter 8A derogation, are now set out in clause 3.8.10 of the Constraints Draft Rule.

The Constraints Draft Rule also sets out the parameters for using an ACF. Clause 3.8.10(e) specifies that NEMMCO can use an ACF only in exceptional circumstances, that NEMMCO must identify the circumstances in which these exceptions may occur and the manner in which it would develop and implement an ACF, and that this process must be transparent and predictable.

One consequence of the Constraints Draft Rule is that any future decision to move away from using the fully co-optimised constraint formulation will require a Rule change and will therefore be subject to a formal consultation process.

Another consequence is that the Rules will no longer need to distinguish between *intra*-regional and *inter*-regional constraints. This is because the fully co-optimised formulation includes both intra- and inter-regional elements. As such, where appropriate, the Constraints Draft Rule replaces references to "intra-regional constraints" and "inter-regional constraints" with "network constraints".

Guidelines for developing, modifying and implementing constraint equations

We recommend that NEMMCO be obliged to develop, publish and comply with "Network Constraint Formulation Guidelines" which explain how it formulates, develops and implements constraint equations and what its policy for managing negative settlement residues is.

We discuss NEMMCO's current policy for managing negative settlement residues in section C.4.

The Guidelines will be a single document, which we expect will consolidate many of NEMMCO's existing publications on constraints (including FCAS constraints), and which will also outline the constraint policies currently set out in NEMMCO's operating procedures.[138] In effect, the Guidelines will be a consolidated reference source for participants seeking information on any aspect of constraint formulation or use.

NEMMCO will determine the specific content of the Guidelines in consultation with participants. NEMMCO will also be required to consult with stakeholders when updating these guidelines.

Implementation

Clause 3.8.10(c) of the Constraints Draft Rule requires NEMMCO to develop, publish and, where necessary from time to time, amend "Network Constraint Formulation Guidelines". These guidelines must identify the process by which NEMMCO will identify or be advised of a requirement to create or modify a network constraint equation. This must include:

- the methodology used to develop the constraint equation terms and coefficients;
- the information sources;

---

[138] These publications include: *Network and FCAS constraint formulation*; *Constraints guide – FCAS constraints*; *Guide to FCAS constraint analysis*; *Basslink Energy and FCAS Equations*; *Operating procedure – Dispatch*; and *Operating procedure – Generic constraints due to network limitations*.

- the means of obtaining information;
- the methodology used to select the form of a constraint equation;
- the process for invoking and revoking constraint equations; and
- the policy for managing negative settlement residues, including both the action NEMMCO will take as well as the threshold trigger for taking action.[139]

Clause 3.8.10(d) of the Constraints Draft Rule requires NEMMCO to comply with the Guidelines.

NEMMCO will be required to develop and amend the Guidelines in accordance with the Rules consultation procedures under rule 8.9 of the Rules.

While the Constraints Draft Rule provides NEMMCO with the power to manage negative settlement residues by intervening in dispatch, clauses 3.8.10(g) to (k) set out the parameters for an AEMC review of this policy. This review will reassess: (1) NEMMCO's use of physical intervention as a means of managing negative settlement residues; and (2) the threshold for intervention.

C.2.3 Physical intervention in the dispatch process

C.2.3.1 Background

Part 8 of Chapter 8A of the Rules currently permits NEMMCO to intervene in the dispatch process to prevent material negative settlement residues from arising. In practice, this is given effect by NEMMCO constraining interconnector flows (clamping) through the dispatch process to prevent negative settlement residues accruing beyond a $6 000 threshold set out in its published Dispatch Operating Procedure.[140] The provision was included in the Rules as a derogation because clamping was anticipated to be an interim solution to the management of negative settlement residues. In May 2006, we extended this derogation from 31 July 2007 to 31 October 2008.

C.2.3.2 Discussion

From the perspective of good regulatory design, discretionary ad-hoc physical interventions such as clamping are inherently problematic and should, if possible, be avoided. Although NEMMCO follows published procedures when invoking clamping constraints, in practice, it is extremely difficult for participants to predict when clamping will take effect and how it will impact dispatch (and pricing) outcomes. This creates risks for participants that are difficult to manage. The cost of

---

139 See section C.4 for a discussion of NEMMCO's current policy.

140 NEMMCO, Operating Procedure: Dispatch, 16 March 2007, http://www.nemmco.com.au/powersystemops/so_op3705v049.pdf.

this uncertainty is likely to be built into contract prices and therefore to customers in the form of higher energy costs. Also, by definition, clamping moves the market away from least-cost dispatch, which reduces economic efficiency (assuming bids and offers are cost-reflective).

We therefore reviewed the impacts of clamping and the case for its continuation. We reviewed the cause of counter-price flows given its financial structure, the mechanisms for funding negative settlement residues, NEMMCO's ability to "carry" a negative settlement residue liability, the firmness of IRSR units, and the impacts of clamping on market certainty and contract market liquidity.

While we concluded that clamping is a less than ideal response to counter-price flows, removing clamping could also distort generators' bidding incentives (i.e. by encouraging dis-orderly bidding). This could lead to less efficient dispatch outcomes.

An option we considered was to increase the threshold for clamping. In the Draft Report, we proposed increasing the clamping threshold to $100 000, for the following reasons:

- An increased threshold will reduce uncertainty for participants around excessive intervention in dispatch and will allow, in more cases, efficient dispatch to continue by delaying intervention.
- The uncertainty for participants created by clamping can flow through to customers as higher energy prices.
- NEMMCO has indicated that it can manage the negative settlement residue liability based on a $100 000 clamping threshold.

In 2006, NEMMCO consulted on lifting the clamping threshold from $6 000 to $100 000.[141] It pursued this change because changes to the funding arrangements for negative settlement residues enabled it to manage a higher negative settlement residue liability.

None of the six submissions to the NEMMCO consultation supported the proposal. The principal reasons related to the implications of funding the accruing negative settlement residues, rather than the intervention threshold itself. The higher threshold would reduce the value of the available settlement residues as a means of managing inter-regional trading risk. Submissions considered the implications of this were greater than the benefits from increasing the intervention threshold.

Three submissions were also concerned that lifting the clamping threshold would permit a longer duration of inefficient dispatch. The basis for this view is that where negative settlement residues reflect dis-orderly bidding, by definition the market is being dispatched on the basis of bids that do not reflect costs.

[141] NEMMCO, Review of Trigger Level for Management of Negative Settlement Residue, Final Determination Report, 27 October 2006, http://www.nemmco.com.au/powersystemops/570-0002.pdf.

We consulted on an option for addressing this specific issue in our Draft Report. In situations where dis-orderly bidding resulted in negative settlement residues, we sought views in the Draft Report (and through a workshop) on an option of "positive flow clamping" (PFC). This option was not supported (see section C.4.3.1 below).

However, one of the reasons submissions did not support PFC was that it would only be used infrequently, meaning there were limited incidences of dis-orderly bidding resulting in negative settlement residues.[142]

This analysis suggests that the issues in respect of dispatch inefficiency raised by submissions in response to NEMMCO's consultation to raise the threshold level are of limited materiality. An implication is that lifting the clamping threshold may allow efficient dispatch previously stopped by clamping to continue longer.

In response to the other concern raised in the NEMMCO consultation, the effect of increasing the threshold will not affect the available settlement residues as an inter-regional hedging instrument. This is because of our related recommendation that NEMMCO ceases its current practice of funding negative settlement residues from positive settlement residues, within a billing week. This is discussed in more detail in section C.4.

The recommendation to increase the threshold trigger to $100 000, therefore, will offer an incremental improvement to the current "clamping" regime. However, as we noted in our draft recommendation, this intervention is not optimal. In the Draft Report proposed a review of both the level of the intervention threshold and the need for physical intervention, more generally, in three years time. The aim, at the time of the review, would be to completely remove the physical intervention if possible.

Finally, to ensure that NEMMCO's use of this intervention is as transparent and predictable as possible, we recommended in the Draft Report that NEMMCO should set out in constraint guidelines (now the Network Constraint Formulation Guidelines, discussed above) its policy for when and how it will intervene in the market to manage negative settlement residues, including setting its intervention threshold.

In their submissions to the Draft Report, Hydro Tasmania and Origin Energy were generally supportive of the recommendation.[143] NEMMCO stated that it could accommodate an increase in the lifting of the threshold and that this would be implemented in its dispatch operating procedures. NGF supported this recommendation but stated that lifting the threshold would have minimal impact upon market dispatch efficiency if clamping is eventually introduced.[144]

---

142 Queensland generators, Draft Report submission, Energy Edge consultancy report, p.13.

143 Hydro Tasmania, Draft Report submission, p.2; Origin Energy, Draft Report submission, p.1.

144 NGF, Draft Report submission, p.7.

Other submissions contended that the case for lifting the threshold had not been made and that further analysis is required.[145] EUAA stated that we had not assessed the likely extent to which the number of physical interventions will be reduced nor the size of the efficiency loss that will persist.[146] TRUenergy was sceptical about the threshold increase because it claimed that it would add uncertainty for participants as to when a NEMMCO intervention is to take place and it may lead to opportunities for gaming.[147] Stanwell, InterGen and Tarong stated in their submission that an obligation on NEMMCO on how it interprets and applies provisions associated with clamping is likely to have greater impact on market liquidity that whether threshold was $6 000 or $100 000.[148] ERAA did not support increasing the threshold because the causes of inefficient negative residues were not addressed.[149]

All submissions unanimously endorsed the recommendation that the Rules should require NEMMCO to identify clearly its policy for using clamping, including how it would implement the policy in practice.[150] One submission added that this would increase market liquidity by ensuring the predictability of pricing and risk management.[151] Macquarie Generation supported the proposal but went further by arguing that there should be an obligation on NEMMCO to report periodically on all incidences where counter-price flows exceed the threshold for negative residues and on the reasons why the threshold was breached.[152]

Our recommendation will require NEMMCO to set out clearly and apply its policy for intervention. This will address the concerns around uncertainty of process around when clamping is invoked. A higher threshold trigger will provide more time for NEMMCO to notify the market of its intention to intervene. This, combined with a clearly articulated policy for intervention, will provide greater clarity around when and how NEMMCO will intervene in dispatch to manage negative settlement residues. This policy could also include reporting on the frequency of its intervention and reasons for it. This is something NEMMCO should consult on when developing its intervention policy.

Regarding the concern that a higher trigger level would prolong inefficient outcomes caused by dis-orderly bidding, as discussed earlier, these circumstances do not appear to materially contribute to the accumulation of negative settlement residues relative to other causes. This is also one of the reasons we are proposing a review in three years of both the threshold trigger and NEMMCO's intervention policy for managing negative settlement residue.

---

145 Macquarie Generation, Draft Report submission, p.3; EUAA, Draft Report submission, p.20.

146 EUAA, Draft Report submission, p.21.

147 TRUenergy, Draft Report submission, p.2.

148 Stanwell, InterGen, Tarong Draft Report, submission, p.3.

149 ERAA, Draft Report submission, p.4.

150 EUAA, Draft Report submission, p.22; NEMMCO, Draft Report submission, p.1; Hydro Tasmania, Draft Report submission, p.2; Origin Energy, Draft Report submission, p.1; InterGen, Stanwell and Tarong Energy, Draft Report submission, p.3; Macquarie Generation, Draft Report submission, p.3

151 InterGen, Stanwell and Tarong Energy, Draft Report submission p.3.

152 Macquarie Generation, Draft Report submission, p.3.

Some participants thought it unnecessary to require this review, given that they themselves are able to seek a review or propose an alternative through the Rule change process. Other participants felt that a review should be held and that it may be necessary to hold it sooner, before three years have lapsed. Our recommendation to have a review does not preclude participants from putting forward a Rule change to consider this issue sooner than three years. In addition, the proposed drafting requires us to commence a review *within* three years of the Constraints Draft Rule commencing, which enables us to conduct the review sooner if required. We consider three years a reasonable timeframe, however, as it will provide time to consider how the current practice operates and to identify where any issues may arise. The requirement to conduct a review does, however, provide a place holder to ensure the issue of NEMMCO intervention to manage negative settlement residues is reviewed in the future.

In conclusion, we acknowledge that allowing NEMMCO to intervene in dispatch to manage negative settlement residues raises a number of issues, but that removing the intervention altogether could also distort generator bidding incentives, which has implications for dispatch and risk management (discussed in section C.4). Therefore, our final recommendation confirms our our draft recommendation.

C.2.3.3 Final recommendations and implementation

We recommend that the Rules:

- allow NEMMCO to intervene in dispatch to manage the accumulation of negative settlement residues;
- require NEMMCO to publish its intervention policy, including the trigger level, in the Network Constraint Formulation Guidelines; and
- require the AEMC to commence a review in three years to consider the efficiency of NEMMCO's intervention policy for managing the accumulation of negative settlement residues, including the intervention threshold level. One of the aims of this review will be to assess the further need for such intervention, with the view to remove it if possible.

We also recommend that NEMMCO raise the intervention threshold for managing negative settlement residues from $6 000 to $100 000.

Implementation

The Constraints Draft Rule implements these recommendations, with the exception of raising the threshold trigger. This Rule is published in Appendix G.

Clause 3.8.1(b)(12) enables NEMMCO to manage negative settlement residues in the central dispatch process, in accordance with its policy as set out in the Network Constraint Formulation Guidelines.

The process for NEMMCO to develop and publish the Network Constraint Formulation Guidelines is set out in claue 3.8.10(c), as discussed above. Clause

3.8.10(c)(v) sets out the specific requirement for NEMMCO to identify its policy in respect to the management of negative settlement residues by intervening in the dispatch process.

Our recommendation to conducting an AEMC review of the intervention policy in three years' time is specified in clause 3.8.10(g) of the Constraints Draft Rule. Clauses 3.8.10(h) to (k) set out the parameters for the review. At the conclusion of the review, we will issue a report and provide a copy to the MCE. We must commence the review within three years, which, as discussed above, does not preclude holding the review earlier than three years, nor considering amendments to the intervention arrangements through Rule change proposals.

NEMMCO currently defines its intervention threshold in its Dispatch Operating Procedure; the threshold is not specified in the Rules. A change to the Rules is not necessary to increase the intervention threshold therefore. The Constraints Draft Rule requires NEMMCO to identify its intervention threshold in the Network Constraints Formulation Guidelines. NEMMCO has confirmed it can implement the higher intervention threshold level. However, given the higher threshold level should be implemented at the same time as the recovery mechanism for negative settlement residues changes, the increased threshold should not come into effect until such time as the new recovery mechanism is in place.

C.2.4 Real-time information on planned network events affecting dispatch

C.2.4.1 Background

Market participants need to take measures to manage the impact of changes to the available network, reflected through the invocation or revocation of constraint equations. When they cannot accurately predict the timing of such changes, and the possible affect on dispatch, they may be exposed to both physical and financial risks. For example, a generator's bids are based on the available information on network availability. If information on planned network events changes with little notice, generators need to manage the impact of these changes. This may mean that generators respond by changing their bids or seeking other ways to cover existing contracts, in order to manage the risk that they are not dispatched, or are constrained-on.

C.2.4.2 Discussion

During the Review a number of participants expressed concerns with the information currently available on when and why NEMMCO invokes or revokes constraint equations, saying that it does not enable them to plan their physical and financial trading positions.[153] Specific concerns were that there is a lack of real-time information on network outages affecting inter and intra-regional flows, a lack of real-time information on changes to the timing of outages, inadequate notification of

[153] See p.2 of the Congestion Management Review Industry Leaders Strategy Forum Summary of Discussion available on the AEMC website: www.aemc.gov.au.

the end of outages, delays in NEMMCO passing on outage information to participants, and insufficient information to fully assess both the physical and market impact of an outage.

Many of these concerns will be addressed by the publication of Network Constraint Formulation Guidelines (as discussed above in subsection C.2.2.2), which will explain NEMMCO's process for invoking and revoking types of constraint equation. This should increase the predictability of NEMMCO's actions. However, these Guidelines will not give participants real-time notification of specific events that lead to the invoking or revoking of particular constraints.

Consequently, we recommended in the Draft Report that NEMMCO must develop (in consultation with industry) and publish information that assists market participants to understand and predict the nature and timing of events that are likely to materially affect constraints in the dispatch process. These events will include at a minimum: network outages, connection and disconnection of generating units or load, commissioning (and decommissioning) of new network assets and new or modified Network Control Ancillary Services (NCAS) and network support agreements.

The intent is to provide routinely to the market a richer and more continuous and consistent flow of information. It will provide the most up to date information on network outages and other planned network events, which will provide participants will a better understanding of how potential changes in system conditions are likely to affect network constraints and therefore influence dispatch. Improvements in information will translate into more informed and efficient decision making for generators and large customers.

The majority of submissions supported this recommendation.

Our final recommendation reiterates the draft recommendation, except we now propose that information about congestion-related network events should be published together with information about mis-pricing in a single, dedicated Congestion Information Resource (CIR). For a more comprehensive discussion of the CIR, including details of participants' views, see section C.6.

C.2.4.3 Final recommendations and implementation

We recommend that NEMMCO must develop and publish information that assists enables market participants predict the nature and timing of events that are likely to affect materially what constraints NEMMCO uses in dispatch. These events include planned network events. This information will be published as part of a CIR.

Implementation

For details of how this recommendation is to be implemented, see section C.6.

C.3 Transmission access, pricing, incentives and investment planning

This section discusses the relationship between transmission and congestion, and examines in more detail the case for incremental change to the Rules in support of more effective congestion management.

C.3.1 Background

In 2006, we reviewed and substantially reformed the Rules relating to the economic regulation of transmission. We have also taken into account reviews and Rule changes that, while not part of this Review process, consider transmission capability, such as the abolition of the Snowy region Rule change and the NTP review. In this Review, we considered and articulated how the different strands of work relate to congestion. We also considered whether the existing Rules require further refinement, having regard to the limited amount of experience of how the new regulatory framework operates in practice.

The relationship between transmission capability and congestion

Patterns of network congestion at any point in time depend in part on how the transmission system can accommodate the pattern of power flows emerging from the dispatch process. As dispatch outcomes relate to the demand for and supply of electricity in various locations of the NEM, supply and demand conditions at any time can directly affect the level of network congestion. An enhanced ability to handle power flows means, other things being equal, a lower likelihood of network congestion occurring, hence reduced physical and financial trading risks for participants.

The ability of the network to handle power flows is referred to as its "capability" and it is capability that comprises the service provided by TNSPs to the market. Capability is a dynamic variable that depends on both the technical design limitations of individual network elements – known as their "capacity" – as well as the way in which those network elements are operated collectively under different power system conditions.[154]

Factors influencing network capability include:

- network assets that are out of service, either for planned maintenance or due to unplanned outages;
- weather events – for example the prospect of lightning may reduce the secure flow limits that can be prudently applied in the dispatch process along a particular transmission route; and

[154] Power system conditions are governed by patterns of generation and demand; ambient conditions; availability of network infrastructure; and the availability of contracted network support & control services (e.g., reactive power capability, and network loading control).

- the operating behaviour of electricity producers and consumers, including how that behaviour might be influenced by network support and control contracts with NEMMCO or TNSPs.

Small changes to the network transfer capability of the existing network can substantially ease congestion and can lead to a dramatic drop in both the level of nodal prices and their volatility.[155] Enhanced network capability, particularly at certain times, may therefore help alleviate the physical and financial trading risks of congestion.

While TNSPs have limited control over many aspects of the power system, they can influence network capability by:

- investing to increase the capacity of network elements;

- maintaining network elements to ensure they are capable of operating to their technical limits (i.e. at their capacities);

- scheduling network outages at times when the value of network capability is relatively low; and

- engaging in other activities, such as the procurement or provision of NSCS to enhance network capability (see section C.3.5 below).

The transmission regulatory regime provides the framework under which TNSPs make decisions about these factors, thereby affecting network capability.

The relationship between transmission pricing and congestion

Another interaction between transmission and congestion is the signals that transmission pricing provides to the market. In particular, what locational signals do transmission pricing in the NEM send to new generators and loads?

Scope of AEMC recommendations and observations

In the previous section, we set out the context for considering what further reforms to the transmission framework we could recommend as part of this Review. In general, because the existing transmission regime was recently reformed, it should be given time to work. Further, we are examining and reforming the related issues of transmission planning and the Regulatory Test as part of our work on the NTP.

However, there are a number of specific areas where we can recommend incremental changes or offer observations to inform our other related work. These areas include:

- clarification of the current arrangements for recouping costs for participant funded network augmentations;

---

[155] CRA, NEM Regional Boundary Issues, 16 September 2004, p.16.

- role of transmission pricing for informing location investment decisions;
- measures of transmission capability; and
- the framework for the provision of NSCS.

We discuss these recommendations and observations in the following sections.

C.3.2 Transmission regulatory framework

C.3.2.1 Background

Chapters 6 and 6A of the Rules addresses the economic regulation of transmission services. They set out the provisions for determining TNSP revenue allowances and pricing methodologies. These provisions seek to create appropriate financial incentives to support efficient decision-making by both TNSPs and participants in relation to investment in transmission, generation and load facilities.

C.3.2.2 Description of the framework elements

Revenue

The two classes of transmission services specified in the Rules are Prescribed Transmission Services and Negotiated Transmission Services. The scope and form of regulation for these two services differs.

Prescribed Services

The Rules provide for a CPI-X revenue cap to be set for each company for Prescribed Transmission Services. The revenue cap is set every five years, using a building blocks cost of service approach, at a level commensurate with efficient operating expenditure, and depreciation and return on efficient capital expenditure. This framework provides a financial incentive for the TNSP to operate more efficiently because it retains (or is exposed to) differences between actual and allowed revenues for the duration of the revenue period.

Service Incentives

Chapter 6A of the Rules provides for the AER to develop a service target performance incentive scheme, whereby up to five per cent of each TNSP's regulated revenue can be put "at risk" if measures of performance are not met. These performance measures are set out in the AER's Service Target Performance Incentive Scheme (Service Performance Scheme).[156]

[156] The AER publishes the Service Target Performance Incentive Scheme under clause 6A.7.4 of the Rules. It must comply with the principles set out in clause 6A.7.4(b).

The scheme principles are intended to encourage TNSPs to provide transmission capability at those times when it is most valued by the market. These would also tend to be the times at which congestion risk is most heightened. These objectives relate directly to the provision of transmission capability on the day-to-day basis, and therefore can contribute directly to the efficiency of the CM Regime.

The current Service Performance Scheme[157] identifies the performance parameters as:

- transmission circuit availability;
- loss of supply event frequency; and
- average outage duration.

TNSPs and the AER then agree on performance targets, collars, and caps for each of the parameters. The current level of revenue at risk attached to a TNSP's performance against its parameters and values is one per cent of its "maximum allowed revenue" (MAR) for the relevant calendar year. The AER measures TNSP performance on a calendar year basis.

The scheme applies to: SP AusNet, ElectraNet, Transend, TransGrid, EnergyAustralia, Murraylink, Directlink and Powerlink.[158] The first calendar year that the AER is applying the scheme is 2008.

Negotiated Services

Revenue for TNSPs from the provision of Negotiated Transmission Services is not subject to a cap. Charges for Negotiated Transmission Services are set under a "negotiate-arbitrate" framework. The provision of new Connection Services is the main form of a Negotiated Transmission Service. The Rules also provide for negotiated transmission network user access. The negotiation between a generator and a TNSP can include a generator agreeing to fund a network augmentation. A generator might do this if the network provided by TNSPs under the regulated incentives delivers an unacceptable (for the generator) level of a dispatch risk. The Electricity Transmission Network Augmentation Connection Guidelines currently published by VENCorp provide further detail on how these arrangements can work in practice under the current Rules.[159]

---

157 Australian Energy Regular, "Electricity transmission network service providers – Service target performance incentive scheme", Final, v01, Melbourne, August 2007. Available: www.aer.gov.au.

158 No parameters apply to VENCorp.

159 http://www.vencorp.com.au/index.php?action=filemanager&folder_id=581&pageID=7770&sectionID=8246

Pricing

The Pricing Rule Determination for Chapter 6A outlined the regulatory framework and principles for setting prices for Prescribed Transmission Services.[160] The regulatory framework section in the Pricing Rule Determination stated that:

- generators should pay the costs directly resulting from their connection decisions, that is, a "shallow connection" approach should be maintained;
- it is not appropriate at this stage for generators to contribute to the costs of the shared network through prescribed generator transmission use of system (TUOS) charges;
- Cost Reflective Network Pricing (CRNP) and modified CRNP are appropriate locational pricing methodologies, however, there should be scope for these to be developed further in future; and
- to some extent price structures should be specified in the Rules with additional guidance provided by the AER.[161]

The Rules maintain a "shallow" connection charging approach for new generation. This means that generators pay charges related to the costs of their immediate connection to the transmission network. New generators are not required to contribute to the costs of downstream augmentations from which they may benefit. At the same time, generators may negotiate with the TNSP to have the TNSP undertake downstream augmentations that may benefit the generator. The generator must pay the relevant costs for the augmentation but is not entitled to explicit financial or physical rights to the incremental transfer capability, however.[162] The Regulatory Test plays a role in establishing the boundary between investment funded by consumers and investment funded by generators.

The cost of the main interconnected network is recovered through charges levied on consumers.

The principles relating to access to negotiated transmission services are set out in clause 6A.9.1 of the Rules. These principles include being able to adjust the price for a negotiated transmission service over time to the extent that the assets used to provide the negotiated service are subsequently used to provide services to another person. The adjustment should take account of costs recovered by the new person.[163] These costs may include capital contributions to the original participant augmentation as well as ongoing operational costs, where appropriate.

---

160 AEMC 2006a, *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22*, Rule Determination, 21 December 2006, Sydney. Available: www.aemc.gov.au.

161 AEMC 2006a, *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22*, Rule Determination, 21 December 2006, Sydney, p.3.

162 However, note that under the Chapter 6A Rules, generators paying for "negotiated services" that are connection services may be entitled to a contribution from later connecting parties (clause 6A.9.1(6)).

163 Clause 6A.9.1(6) of the Rules.

The corresponding access arrangements relating to transmission networks are in rule 5.4A of the Rules.[164] These provisions set out the negotiating framework for TNSPs and connecting applicants or participants to determine the conditions for access to the transmission network.

Further, there are a series of provisions broadly relating to the topic of "firm access", in which TNSPs and participants make various "compensation" payments to one another under different market conditions (see rules 5.4A(g)-(h) and 5.5(f)(4)). However, agreements or payments under these Rules have not been implemented to date.

More detailed comments and discussion related to transmission access specifically, including rule 5.4A, are discussed separately in section C.3.3.

C.3.2.3 Discussion

The charges for Prescribed and Negotiated Transmission Services levied by TNSPs represent one influence, among many, on generator locational investment decisions. Where generating capacity is built, or retired, affects future patterns of network congestion and the accompanying trading risks. (See section C.4 for more information.)

When we concluded our review on the framework for transmission pricing in December 2006, we supported the continuation of a "shallow" connection charging policy. We came to this view of a number of reasons.

First, the nature and timing of network investment is primarily determined by prescribed reliability criteria and hence a shallow connection charging approach is consistent with the "causer pay" principle. In other words, generators do not "cause" new transmission investment to be undertaken simply by virtue of their locational decision. Investment is driven by the need to meet reliability standards for load, or to deliver market benefits. Of course, generators are always free to fund augmentations under the Negotiated Transmission Services provisions. Effectively, this means that the arrangements implement a *de facto* deep connection charging approach for investment that is not demonstrated as being efficient.

Second, the regulatory and market arrangements already provide locational signals to generators (e.g. price separation between regions, the use of marginal loss factors in dispatch and settlement, the risk of being constrained-off) and differences in the availability of fuel, land and water, such that further signalling through transmission charges was not warranted.

Finally, we agreed with market participants that deep connection charges may create additional regulatory complexity and deter new generation investment, thereby

[164] Rule 5.5 sets out the negotiating framework for access arrangements relating to distribution networks.

harming competition and the long-term interests of end-use consumers.[165] We did, however, undertake to review this position in the light of this Review.

Through this Review process, some market participants made submissions advocating the introduction of additional capacity or access charges into the current framework of transmission service pricing. These charges would expose new entrants to the incremental effect on congestion caused by their location without introducing greater price granularity. (See boxes C.1 and C.2 below for more detail).

Box C.1: Delta Electricity proposal – Deep connection charges

Delta Electricity suggested a variation of a "deep" connection approach. It proposed that new generators should pay the cost of downstream augmentations if their investment location increased congestion on the network.

The TNSP would determine the additional cost of any long term network augmentation (long run marginal cost or LRMC) required to avoid congestion occurring. If the new generator locates where there is ample transmission access or where the network is likely to be augmented as part of the least cost plan, the LRMC would be zero. If, for whatever reason, the generator locates where congestion does result and the LRMC is positive (and above a tolerance level), then the generator would be exposed to that cost.

Delta Electricity contended that such arrangements would lead to greater alignment between regulated investment in transmission and market driven investment in generation and more efficient generation location decisions. There would be no explicit transmission rights under the Delta proposals, but the implicit rights for existing generators would be "firmed up".

The NGF considered that other connecting parties were unlikely to agree to pay charges that reduced the cost incurred by the original investor, particularly in the case of a "deep" augmentation.[166]

"The Group" also advocated for a deep connection charge linked to access payable by generators when deciding upon potential investments. In its view, current transmission pricing arrangements lead to inefficient investment in transmission and generation. Deep connection charge would provide a key investment signal to generators and effectively provide access certainty to new and existing generators, thereby reducing investment risk.[167]

EUAA stated that it supported the approach that transmission connected generators should contribute to system costs, e.g. a deep connection charge, because this would act as an incentive on TNSPs to behave efficiently because of pressure from

[165] AEMC 2006, *Pricing of Prescribed Transmission Services*, Final Rule Determination, pp.21-22.

[166] NGF, Congestion Management Review- Directions Paper submission, 13 April 2007, p.10.

[167] "The Group", Draft Report submission, p.4.

generators.[168] It was critical of what it sees as insufficient incentives on TNSPs to manage congestion either in the current pricing regime or the Service Target Performance Incentive Scheme and advocated for further transmission reform.

Box C.2: Southern Generators' Proposal – explicit financial access rights

In a supplementary submission in November 2006, the Southern Generators contended that transmission rights were essential in removing or lowering existing entry barriers for new generation investment. They proposed a system of explicit financial access rights which would give parties the right to a specified level of access to the local RRN or to be compensated if this level of access is not specified. They stated that this access right will not be firm, in the sense that physical access would not be guaranteed to the holder. The Southern Generators also proposed that incumbent generators would be allocated access rights ("grandfathered") but any new entrant would have to pay to obtain access rights.

This proposal for explicit financial rights for settlement at the RRP differs from the arrangement suggested by the LATIN Group for full rollout of CSC/CSPs (discussed in section C.5). Although both proposals have the similar goal of providing certainty for incumbent generators to have access to the RRN, the financial access rights arrangement would not include generator nodal prices. This leads to issues regarding how such access rights should be valued under the proposed arrangement. In their proposal, the Southern Generators suggested that the access rights be valued at lost profit suffered by the incumbent when access is transferred to the new entrant.

The Southern Generators advocated their proposal on the grounds that it would improve the efficiency of locational investment decisions. They stated that such an financial access right system would force new entrants to factor in congestion costs imposed on other generators to their investment decisions. As a consequence, access would be more certain for all generators. Rights allocated to incumbent generators would compensate them for any reduction in access caused by that new entrant. The Southern Generators contended that this may prevent the current bidding wars between generators trying to gain access to the RRN price.

We continue not to favour a "deep connection approach", like that proposed by Delta Electricity proposal, for similar reasons to those set out in its 2006 pricing decision and summarised above. Further, a network augmentation in the light of a new connection impacts on the ability of both new and incumbent generators to operate. Hence it is not immediately clear why a new generator should have to pay a charge to continue to use the (enhanced) network. From an efficiency perspective, signals to close are important in a similar way to signals to perspective new generators.

With respect to the Southern Generators' Proposal, we note the similarities between this and the CSP/CSC rollout option put forward by the LATIN Group (discussed in

168 EUAA, Draft Report submission, p.30.

section C.5). Both options effectively provide existing generators with financial compensation for congestion. The CSP/CSC approach provides incumbent generators with compensation for the settlement price impacts of congestion in a locational pricing environment while the financial access rights approach provides incumbents with compensation for not being dispatched due to congestion. In either case, we do not believe that the present materiality of congestion warrants such a substantial change to the market design.

Our recommendation on transmission pricing in the Draft Report was to not amend the current transmission pricing Rules in order to improve location signals on new generators. In coming to this position, we recognised that the location of a new generator may impose costs on other participants. We understood that new generators can increase congestion, which can lead to other generators facing dispatch risk and being constrained-off. However, we did not consider that the case for substantial reform was strong enough at this time.

Further, as discussed in section C.5, the existing arrangements already provide a variety of locational signals to inform investment decisions. These include negotiated transmission charges and the fact that generator locational decisions are influenced by a series of non-price factors, such as access to fuel and water, as well as environment obligations and so on. Finally, locational signals are provided by the current provision of non-firm access to the RRP. For these reasons, we do not believe that changes to the current transmission pricing Rules to improve locational signals on new generators are warranted at the present time.

In the context of the NTP review[169], though, we did consider it appropriate to provide recommendations to the MCE on the design of a new framework for inter-regional transmission charging. We highlighted the weaknesses of the current regime for inter-regional charging in the 2006 review of economic regulation for transmission, although we did not provide explicit recommendations. Having re-evaluated this position in the context of the NTP review, we consider that the implementation of a formal and transparent inter-regional transmission charging arrangement is essential to the development of a national and co-ordinated transmission grid. The Energy Reform Implementation Group (ERIG) reached a similar conclusion in its final report to the Council of Australian Governments (COAG).[170]

In the NTP Draft Report, we presented and sought stakeholder comment on four possible inter-regional charging options.[171] In the NTP Final Report, we intend to set out a preferred approach, and define a work program to develop a detailed design and implementation plan.

In light of the substantial climate change reform agenda and its direct affect on the operation and development of the NEM, it is likely that the pattern of congestion in the future will look significantly different from what it looks like today, and in the

[169] We discuss the National Transmission Planner review in more detail in section C.3.

[170] ERIG, Final Report to COAG, January 2007, p.180.

[171] AEMC, NTP Draft Report, pp.50-55.

past. That being said, it is still uncertain as to what the pattern will be. Therefore, it is difficult to know now what, if any, changes to the transmission pricing framework would facilitate investment decisions in this uncertain environment. This matter would benefit from further review in due course.

C.3.2.4 Final observations

As discussed above, the transmission regulatory framework set out in Chapter 6A of the Rules is only in its first few years of operation. It needs an opportunity to establish itself to determine whether further reforms are necessary, and where the reforms should apply. This particularly relates to the revenue framework.

The current level of congestion does not warrant a change to the transmission pricing framework at this time. However, given the substantial yet unknown affect the climate change reform agenda will have on the NEM, there is a question as to whether we should revisit the recommendation not to amend the transmission pricing Rules. Once there is a clearer view on the climate change reform package and its interactions with the NEM, there will be a more informed environment to determine what role, if any, transmission pricing should have in informing future investment decisions.

C.3.3 Network access

C.3.3.1 Background

As discussed in section C.3.2, negotiated transmission services represent an important element of the overall CM Regime. They can provide locational signals to generators considering investment options. The direct cost of connection provides one form of signal. The scope for generator-funded network augmentations provides another form of signal. This has relevance where the quality of access required by the generator is greater than can be supported by network investment consistent with satisfying the Regulatory Test.

A potential barrier to efficient responses to these signals is the risk that a generator who funds a network augmentation does not realise the full benefits of the augmentation because another generator connects subsequently. This is the "first-mover" problem and might deter otherwise efficient investment occurring. The Rules provide for this contingency through two routes. First, by providing for a generator to negotiate an explicit level of transmission network user access with a TNSP. This could, for example, stipulate compensation payments if the level of service was reduced. Second, by providing for costs to be recouped (or charges reduced) in the event that another user's connection impacts on the service being provided to the "first mover".

C.3.3.2 Discussion

A number of stakeholders made submissions on the current operation of this area of the Rules, citing a number of weaknesses around the effectiveness of the negotiated access charges clauses contained in Chapter 5 of the Rules.

Hydro Tasmania was concerned that if a generator wished to improve its access by funding an upgrade in the shared network, it could not obtain access rights over the enhanced transfer capacity.[172] AGL observed that the rules on negotiated access in Chapter 5 of the Rules have not been successfully applied.[173] If they were effectively applied, generators would pay an increasing portion of total TUOS costs over time.

The NGF also considered that free rider concerns and the lack of any firm arrangements to compensate or reimburse a generator for a loss of asset value needed to be revisited.[174] It raised that rule 5.4A should be strengthened to improve the arrangements for negotiated transmission access. In its submission to the Draft Report, the NGF provided a consultancy report from Synergies Economic Consultants proposing two models (a Strong and a Weak model) to clarify the property rights arrangements between incumbent generators contributing to augmentation, new generators and network service providers. The object of these suggestions was to provide certainty for generators seeking to negotiate a required level of market access.[175]

Under the Strong method, generators who augment the network would be entitled to defined compensation. Under the Weak method, generators would be able to pay to augment the network (by paying TNSPs the difference between the cost of the augmentation and the justifiable cost under the Regulatory Test). Under this latter method, a new generator would compensate an incumbent generator where:

1. the new generator connects to the same part of the augmented network; and

2. the new generator's connection reduces the network availability to the incumbent.

"The Group" also echoed these concerns arguing that both rule 5.4A and rule 5.5 have the intent of providing explicit financial or physical rights to transfer capability, but in practice are not workable because: (1) the Rules are in conflict with other provisions intended to deny generators any right to receive explicit financial or physical rights to transmission transfer capability; (2) relies on TNSPs negotiating compensation on behalf of participants; (3) TNSPs may view provision as increasing

---

[172] Hydro Tasmania, Draft Report submission, p.6.

[173] AGL, Submission to the Ministerial Council on Energy's (MCE) Standing Committee of Officials (SCO) National Electricity Market: Regional Structure Review Consultation Paper, Sydney, 14 November 2004, p.4. http://www.mce.gov.au/assets/documents/mceinternet/AGL20050114143758%2Epdf .

[174] NGF, Congestion Management Review- Directions Paper submission, 13 April 2007, p.10.

[175] NGF, Draft Report submission, 4 December 2008, p.2.

their financial exposure and have little incentive to take on risk; and (4) TNSPs have no incentive act as negotiator of access rights.[176]

While we acknowledge and welcome the points made in submissions, the adoption of alternative models for transmission access represents a significant change to the current NEM market design. The current evidence on the materiality of congestion does not support such a significant change at this time. These models may, however, have relevance to the longer term development of the CM Regime, as discussed in chapter 4 of this Review's Final Report.

That being said, our analysis indicates that the existing provisions in the Rule related to transmission network access can be more clearly and directly stated. In particular, this includes making explicit the requirement that recouped costs (or reduced charges) should be negotiated between a generator and a TNSP, and not unilaterally imposed by a TNSP.[177] This clarification will provide greater certainty for these generators, thereby improving the overall effectiveness of the locational signal.

In early May, we consulted on an Exposure Draft and the *Draft National Electricity Amendment (Network Augmentations) Rule 2008* (Network Augmentations Draft Rule) proposing changes to the current Rules that would clarify the current arrangements.[178] Submissions raised several issues around the clarification we proposed to make.

A group of generators[179] (THALIF) and the NGF stated that the clarification we proposed did not address the more fundamental issue they raised in their Draft Report submissions: ways to improve the compensation provisions in rule 5.4A to better manage congestion and provide firmer generator access.[180] Both these submissions recommended that we do not make the proposed clarification and wait for a formal Rule change proposal to address the more fundamental issues they had identified.

The THALIF submission raised two additional issues. The first was it identified a current link between the negotiated transmission principles and rule 5.4A already existed, in clause 6A.9.2(b), and therefore, this additional clarification is unnecessary.[181] The second was that it considered the proposed changes "may lend

---

176 "The Group" includes Loy Yang Marketing Management Company, AGL Energy, International Power, Flinders Power, InterGen Australia and Hydro Tasmania, Draft Report submission, pp.17-19.

177 The recommendation makes explicit the link between the principles for negotiating transmission network access under clause 6A.9.1 of the Rules and the rules on access arrangements for transmission networks in rule 5.4A.

178 AEMC 2008, Congestion Management Review, Exposure Draft - Arrangements for recouping costs for participant funded network augmentations, 2 May 2008, Sydney. Available: www.aemc.gov.au.

179 International Power, LYMMCO, AGL Energy, TRUenergy, Hydro Tasmania, and Flinders Power (THALIF)

180 THALIF, submission on Exposure Draft on participant funded network augmentations, p.2; NGF, submission on Exposure Draft on participant funded network augmentations, p.1.

181 THALIF, Network augmentation Exposure Draft submission, p.3.

weight" to the view that rule 5.4A only applied to generators that sought negotiated transmission services.[182]

Submissions from Grid Australia, VENCorp and Major Energy Users (MEU) were broadly supportive of the proposed clarification.[183] The first two organisations sought to confirm that the intended clarification was to recognised the connection between the negotiated services pricing principles in Chapter 6A and the negotiated use of system charges payable under clause 5.4A(f)(3), not the access charges, and therefore the compensation provisions, in clause 5.4A(h).

We note clause 6A.9.2(b) includes a cross reference to rule 5.4A. However, there is not currently a reciprocal reference in 5.4A to Chapter 6A. A link connecting these two parts of the Rules will provide greater clarity, transparency, and useability. The same reasoning applies to the proposed note in clause 6A.9.1(6). The drafting note provides greater clarity around what types of events may lead to an adjustment in the cost of a negotiated transmission service as does the reciprocal reference in rule 5.4A. While the proposed changes may not be as substantive as proposed in submissions to the Draft Report, they improve the clarity of the arrangements in the Rules, which is an incremental improvement to what is currently there.

In response to the comments made by Grid Australia and VENCorp, the cross reference previously proposed in clause 5.4A(f)(3) of the Network Augmentation Draft Rule is now made as a new clause 5.4A(f)(5). This clarifies the connection between the negotiated services pricing principles in Chapter 6A and the negotiated use of system charges payable under clause 5.4A(f)(3), not to the access charges.

Regarding the second issue raised by THALIF, it is not the policy intent to of proposed clause 5.4A(f)(3) to change the interpretation of rule 5.4A. Rather, the intention is to clarify the current arrangements, particularly the method under which a generator may recoup costs from a later connecting party who benefits from a funded network augmentation. We do not consider that the Network Augmentation Draft Rule changes the current operation of rule 5.4A.

Submissions also raised some additional issues that go beyond the scope of our recommended clarification.

C.3.3.3 Final recommendations and implementation

We consider the provisions currently in the Rules relating to circumstances in which generators choose to fund a network augmentation in the context of negotiating its connection service with a TNSP can be clarified and strengthened. We recommend making it clear that the requirement that recouped costs (or reduced charges) should be negotiated between a generator and a TNSP and should account for circumstances where another party connects to the network and benefits from an existing

[182] THALIF, Network augmentation Exposure Draft submission, p.5.

[183] Grid Australia, submission on Exposure Draft on participant funded network augmentations, p.1; VENCorp, submission on Exposure Draft on participant funded network augmentations, p.1; MEU, submission on Exposure Draft on participant funded network augmentations, p.1.

participant funded network augmentation. This clarification will provide greater certainty for these generators, thereby improving the overall effectiveness of the locational signal.

Implementation

The Network Augmentation Draft Rule makes two amendments to the Rules to implement this recommendation. The first includes a drafting note in clause 6A.9.1(6) to clarify that an adjustment as referred to in this clause may be appropriate where: (1) the cost of providing the negotiated transmission service changes because the assets used to provide that service are subsequently used to provide a service to another person; and (2) the payment for the service by that other person enables the TNSP to recoup from of those costs from that other person.

The second clarifies that when a generator and a TNSP are negotiating transmission access, including use of system charges, these negotiations should be conducted in a manner consistent with clause 6A.9.1. This Draft Rule does this by introducing a new clause 5.4A(f)(3).

The Network Augmentation Draft Rule is published in Appendix G.

C.3.4 Transmission investment planning

TNSPs are responsible for investment planning in their area. The Rules stipulate a process of consultation and assessment that must be following before investment is undertaken. We are currently undertaking related reviews considering reforms to the existing transmission planning framework. The following sections outline the existing investment planning framework and discuss the related reforms currently under consultation.

C.3.4.1 Background

Under Chapter 5 of the Rules and jurisdictional instruments, TNSPs are required to plan and develop their transmission networks so as to ensure that power quality and reliability are met for both normal and outage conditions. The planning process undertaken by TNSPs starts with an analysis of emerging limits in the transmission system as load grows over time. This process involves a review of load and generation across the network and includes detailed load-flow analysis. The options to remove or relieve these limits are then developed and compared, and, as required by the Rules, consulted on with stakeholders through the Annual Planning Report (APR) process.

The Rules also require TNSPs to subject proposed network investments to the AER's Regulatory Test, to ensure their investments represent the most efficient option compared with a range of genuine and practicable alternatives, including demand side management and other local generation solutions. TNSPs are only permitted to undertake those investments that satisfy the AER Regulatory Test.[184] The Regulatory Test comprises two alternative "limbs", one of which an investment must satisfy prior to being able to proceed. These are the:

- **reliability limb**: a project satisfies the reliability limb if it meets a prescribed reliability criterion at least cost; and

- **market benefits limb**: a project satisfies the market benefits limb if it maximises the expected net present value of "market" benefits (being benefits to consumers, producers and transporters of electricity less the costs of the project).

In determining how to reduce congestion, the current Regulatory Test is intended to ensure that TNSPs develop only efficient network augmentation options and properly consider non-network alternatives.

In November 2006, following a review of the market benefits limb, we made a Rule outlining principles for a revised Regulatory Test.[185] The new Rule imposes much more specific principles for the market benefits limb of the Test, including a requirement for TNSPs to publish a request for information where they are assessing a potential "large new transmission network investment". This will help ensure that all relevant options are considered under the market benefits limb of the Test.

In March 2007, the Rules were amended to provide us with the power to direct TNSPs to undertake a Regulatory Test assessment for a particular network problem or transmission investment under certain circumstances. This is known as the Last Resort Planning Power (LRPP).[186] Its purpose is to ensure that appropriate consideration was given to congestion-relieving transmission investments in circumstances where TNSPs may lack incentives to apply the Regulatory Test. Importantly, the LRPP is a "safety net" that will only be exercised as a "last resort".

The issue of how transmission investment is planned and remunerated was considered, among other matters, by the ERIG. ERIG's Final Report was provided to COAG on 12 January 2007. ERIG concluded that there were three elements to developing an efficient national transmission grid:

- improved locational signals to generators;

- a stronger incentive framework for TNSPs; and

- an improved national transmission planning mechanism to better coordinate and integrate the development of the national power system.

---

[184] Note that Chapter 6A does not make this a prerequisite to including the expenditure in the TNSP's forecast capex (see clause 6A.6.7 of the Rules).

[185] AEMC 2006, *Reform of the Regulatory Test Principles*, Final Determination, 30 November 2006, Sydney.

[186] AEMC 2007, *National Electricity Amendment (Transmission Last Resort Planning) Rule 2007*, Rule Determination, 8 March 2007, Sydney.

In its communiqué of 13 April 2007, COAG announced its decision to establish an enhanced planning process for the national electricity transmission network to promote more strategic and co-ordinated development of the transmission network and to assist in optimising investment between transmission and generation across the power system. On 3 July 2007, the MCE directed us to develop a detailed implementation plan for a NTP. This included changes to the transmission planning arrangements, regulatory arrangements, and the current Regulatory Test. We published our Draft Report on the NTP on 2 May 2008.

C.3.4.2 Discussion

National Transmission Planner

We commenced our NTP review once we received the MCE's Terms of Reference. The NTP Terms of Reference included reviewing changes to the transmission planning arrangements, regulatory arrangements and the current Regulatory Test. The MCE also requested that the we undertake a review of transmission network reliability standards, with a view to developing a consistent national framework for network security and reliability. We provided a reference to the Reliability Panel for the Panel to undertake this review in August 2007.[187]

In May 2008, we published the NTP Draft Report.[188] The Draft Report sets out the objective for the NTP as well as specifying its functions. It also sets out the implementation plan for establishing the NTP.

The NTP objective is to:

> "comply with the National Electricity Objective in a manner which promotes the efficient long term and nationally coordinated development of the transmission network."

In carrying out its functions to meet this objective, the NTP will make available to the market information about congestion. This information will focus on identifying points of congestion and how congestion may translate into transmission capability issues.

The key NTP function will be to prepare a National Transmission Network Development Plan (NTNDP) each year. Accompanying the NTNDP, the NTP will publish a database of information, data and methods used in producing the NTNDP. A high-quality NTNDP will be based on robust and demonstrably transparent analysis. The obligation to publish a database of information used to derive the plan

[187] On 24 April 2008, the Reliability Panel published its Draft Report, "Towards a Nationally Consistent Framework for Transmission Reliability Standards". The Draft Report responds to submissions to the Reliability Panel's Issues Paper, puts forward the Panel's draft findings and recommendations, and seeks further comments from interested parties, before preparing its final report to the AEMC. Available: http://www.aemc.gov.au/electricity.php?r=20071221.150018.

[188] AEMC, National Transmission Planning Arrangements, Draft Report, 2 May 2008. Available: www.aemc.gov.au.

will contribute significantly to this and will assist both public and private sector investors.

The focus of the NTNDP is strategic and long term, looking out 20 years at a minimum. It will focus on National Transmission Flow Paths (NTFPs) and will include all those transmission elements that are part of or materially affect the transfer capacity of the NTFPs.

The NTNDP will map out development strategies under a range of scenarios for the efficient delivery of transmission capability across the NTFPs. The development strategies are likely to involve a combination of network and non-network solutions and assess the optimisation of generation and transmission investment. The precise pattern of the NTFPs may change over time, and may vary across planning scenarios, and this framework enables the NTP to respond dynamically to changing circumstances and new information while avoiding the risk of being drawn into the detail of localised planning issues.

The NTP will be required and resourced to produce its own development strategies, including, its own transmission investment options. The NTNDP will therefore be less reliant on conceptual augmentations suggested by the TNSPs, as is currently the case with NEMMCO's production of the ANTS. The NTNDP will look at both reliability and market benefits projects and will provide a deeper and longer term scenario-based assessment of power system development to the market.

The NTP's modelling will reflect:

- key transmission capability issues, including forecast constraints, which require action to enlarge or to increase the capability of the NTFPs to transmit or distribute electricity; and

- options, include network and non-network options, which, in the NTP's reasonable opinion, have the technical capability of addressing the identified key capability issues across identified NTFPs.

In addition, the NTNDP will reference relevant historical time series information on the patterns of congestion and mis-pricing in both system normal and non-system normal conditions. As discussed in section C.6, this information is to form part of the CIR.

The NTP will provide existing and future participants with information on transmission network capability and congestion on a forward-looking basis. This, combined with the information provided in the CIR, provides participants with a robust framework to consider how congestion is likely to and may in the future affect them.

It will also inform and improve the shorter term investment planning activities of TNSPs. This planning and the NTNDP should work to complement each other in promoting efficient outcomes for consumers. In the NTP Draft Report, we recommend that the NTP must have regard to the APRs of each TNSP in preparing the NTNDP, and that each TNSP must have regard to the NTNDP in their APRs. TNSPs must also explain how their investment plans relate to the NTNDP in their

APRs, and the NTNDP will also contain a consolidated summary and commentary on the APRs of each of the TNSPs. This will not alter the accountability of individual TNSPs, but it will enhance the information available to TNSPs in undertaking their planning. This is likely to promote a more co-ordinated approach to the development of the NEM's transmission network over time.

Recommending a new Regulatory Test

In the NTP Draft Report, we are also consulting on a new project assessment and consultation process for transmission. The new process would replace the existing Regulatory Test; it is called the Regulatory Investment Test for Transmission (RIT-T).

As part of the NTP Review, the MCE tasked us to advise on amalgamating the Regulatory Test criteria of reliability and market benefits. The recommended RIT-T will require TNSPs to consider both network and non-network solutions that benefit the national market.

As set out in the NTP Draft Report, the TNSPs will undertake the RIT-T when a transmission network planning issue exists where: the most expensive economically credible option is estimated to cost more than $5 million; the planning issue is not urgent or unforeseen; and the planning issue is not solely the provision of connection services nor negotiated transmission services or like-for-like replacement.

The purpose of the RIT-T will be to identify the preferred option which maximises the present value of net economic benefits (or minimise the present value of net economic costs) subject to meeting deterministic reliability standards (where they apply). Considered options will include both network and non-network solutions.

The proposed RIT-T will help improve the incentive framework for alternative solutions, like demand-side solutions or embedded generation, addressing concerns expressed by the Total Environment Centre (TEC).[189]

Measures of transmission capability

A key interaction between transmission and congestion management relates to the provision of transmission capability. As noted above, this is influenced by a range of short-term and long-term factors, e.g. how network outages are scheduled, what network control and support arrangements are in place, levels of network investment, and how network assets are maintained. The efficiency with which these activities occur will impact directly on the efficiency of congestion management regime.

We observe that a limiting factor on promoting efficient transmission services from the perspective of congestion management is the absence of measures of the "outputs" that matter from a congestion management perspective, i.e. transmission capability. The AER work program to develop system service incentives is an

---

189 TEC, Draft Report submission, pp.1-2

important element in promoting efficiency in this regard, but is necessarily based around partial output measures, e.g. patterns of outages, in the absence of more general metrics of transmission capability.

In a supplementary submission, Delta Electricity suggested making information available on connection point to load centre transfer capability and also on the network locations that can accept further generation injection without exacerbating congestion.[190] It also suggested publication of information on the cost of network augmentation to relieve any congestion caused if generation were to be injected above those levels. Delta Electricity considered this information could help investors evaluate locations for potential new connections. Submissions from TNSPs to the Direction Paper noted that information on connection point transfer capability is already commonly provided as part of the connection application process, and questioned the value of the other information cited by Delta Electricity given the likely sensitivity to the assumptions being used.

In its submission to the Draft Report, NEMMCO commented that there was a broad range of factors that could impact the transfer capability of any set of network elements.[191] For example, the flow limit on a set of transmission lines may be limited by any combination of:

- infrastructure ratings and availability (transmission elements in or out of service);
- ambient conditions (temperature and wind speed);
- availability of static or dynamic reactive capability;
- availability of customer load management or generation support; and
- load and generation patterns.

Network capability cannot therefore be adequately described by a single number because the network constraints used in the NEM dispatch process to account for these limitations can bind at a range of power flow levels. Therefore, a range of values is necessary to express network capability.

NEMMCO identified the type of information currently published in Appendix F of the SOO-ANTS that informs network capability. It noted however, that this information is currently used for information and planning purposes and therefore different approaches may be necessary to meet the network capability information needs.

More disaggregated information (e.g. for a much larger number of flow paths) on network capability would confer benefits beyond enabling a potential enhancement of a TNSP incentive scheme. As discussed in section C.6, this would also improve the ability of market participants to predict the likelihood of congestion and could also provide greater general transparency to the market on what outputs are

---

[190] Delta Electricity, supplementary submission, Congestion Management Review, 9 November 2006.

[191] NEMMCO, Draft Report submission, pp.12-15.

delivered by TNSPs. Stakeholders supported additional information on transmission capability.[192]

It is not necessarily straight forward to develop this additional information from current information sources.[193] It is also unclear what the costs of publishing the additional information would be using these existing systems. It is possible that the costs may outweigh the possible benefits from making this information available to potential investors.

That being said, work should be undertaken to develop better measures of transmission capability, and this should be given effect through obligations in the Rules. There is a question as to which party should have primary responsibility. There are a number of options, reflecting the multiplicity of potential uses for such measures. For example, the AER could lead the process with NEMMCO providing support technical advice, or NEMMCO could lead with a requirement to consult closely with the AER.

Informed by our work on NTP, we consider the NTP is the most appropriate body to undertake this work. As discussed above, the NTNDP will therefore include information on transmission capability.

Demand Side Participation Review

We are currently progressing another review on Demand Side Participation (DSP), which also interacts with this Review. As part of th DSP review, we are investigating, among other things, whether the incentives in the framework for the economic regulation of networks allow for the efficient use of non-network options (such as DSP).[194]

In May 2008, we published the Final Report for Stage 1 of the DSP Review, prepared by NERA Economic Consulting.[195] Stage 1 considers DSP in the context of the AEMC's current work program, including this Review. The two relevant recommendations in this Stage 1 Final Report related to measuring transmission transfer capability; and facilitating DSP as a means of providing NCAS in the market. We discuss the latter recommendation in section C.3.5.

The Stage 1 Final Report recommended that:

- "the NTP be given the responsibility to develop measures of longer term transmission transfer capability and, where feasible, publish transfer capability at each distribution network connection point; and

192 TEC, Draft Report submission, p.2.

193 NEMMCO, Draft Report submission, p.12.

194 AEMC, Statement of Approach, Attachment A - Review of Demand-Side Participation (DSP) in the NEM, 3 March 2008.

195 NERA Economic Consulting, "Review of the role of demand side participation in the National Electricity Market" – Stage 1 Final Report", Report prepared for the AEMC, 9 May 2008, Sydney. Available: www.aemc.gov.au.

- the [AEMC] further examine the costs and benefits of placing an obligation on TNSPs to estimate the amount of DSP needed to address identified areas of congestion, and when the DSP would be required."[196]

From the discussion on the NTP above, measuring transfer capability is a key component of the NTP's remit. The first component of this recommendation is therefore being actively considered and consulted on in the NTP Draft Report.

At this late stage in this Review, we are not able to provide information proposed in the second component of the above recommendation in this Final Report. We do, however, consider that the RIT-T will provide a framework for considering non-network solutions, like demand side participation, as possible options for addressing congestion.

C.3.4.3 Final observations

The number of related reforms currently underway will significantly improve the transmission investment planning arrangements. The NTP will introduce a more co-ordinated approach for developing the NEM's transmission network over time. The NTNDP's strategic focus will provide participants with information to promote efficient investment decision making, further informed by forward-looking information about network capability and congestion.

The RIT-T will assist TNSPs to identify the preferred option that will provide the greatest economic benefits (present value), while continuing to meet the relevant reliability standards. Importantly, it will improve the incentive framework for considering alternative, non-network solutions (including demand side solutions). In addition, the LRPP provides a "safety net", to only be exercised as a "last resort".

Having progressed our consideration in these inter-related matters and reviews in a co-ordinated integrated manner, this combined package of reforms will provide a robust investment planning framework going forward. We do not consider there are any specific recommendations we can make in the context of this Review that would add value to the reforms currently being pursued as part of the NTP review, in particular.

C.3.5 Network support and control services

The previous section discussed, transmission capability at any given point in time depends on a number of factors. One such factor is the provision of NSCS. NSCS are those services procured and delivered by TNSPs or NEMMCO for the purpose of managing network flows to ensure secure and reliable operation of the power system or to enhance capability and thereby delivering a market benefit.

[196] NERA, DSP Review Stage 1 Final Report, p.45.

C.3.5.1 Background

The NSCS currently procured and delivered include:

- **Network Support Services** – procured by TNSPs via contracts with third parties (network support agreements (NSAs)), e.g. generators or load agreeing to be constrained-on (or off) in specified circumstances;

- **Network Control Ancillary Services** (NCAS) – procured by NEMMCO via contracts with Market Participants (not TNSPs) as either reactive power ancillary service (RPAS) in the form of voltage control, or network loading control ancillary service (NLCAS) e.g. rapid generator unit loading or load tripping scheme.

In addition, TNSPs can deliver some forms of network control services from their own infrastructure, such as reactive power capability from capacitor banks or static var compensators. The provision of such services can obviate the need for agreements to be struck with market participants. Appendix E provides further detail on the provision of NSCS.

Under the Rules, NEMMCO has the ability to procure NCAS as a means of ensuring sufficient capability to support meeting the power system security and reliability standards under the Rules. NEMMCO may also procure NCAS to assist in maximising the value of spot market trading. The costs of these services are recovered as part of NEMMCO's market fees (i.e. through general charges across the whole market). TNSPs are prohibited from submitting tenders to NEMMCO for the provision of NCAS above and beyond the levels required by jurisdiction-specific security and reliability requirements can affect the effectiveness of the current arrangements. TNSPs may use NSCS, however, to meet their reliability obligations under the Rules, jurisdictional requirements, or other service levels negotiated with individual connecting parties in connection agreements.

C.3.5.2 Discussion

The efficient procurement and delivery of NSCS is a component part of an efficient congestion management regime, although it is important to recognise the wider purposes of NSCS, e.g. in terms of system security and reliability. The development of more sophisticated measures of transmission capability will provide greater visibility on whether and how NSCS can be used to support more efficient congestion management – and refined incentive schemes can be used to reward TNSPs for the efficient use of NSCS-type solutions to the problem of delivering valued transmission capability from a congestion management perspective.

There are, however, two additional issues relating to the provision of NSCS where we wish to make observations. The first issue concerns the revenue treatment of NSCS solutions for TNSPs. The second issues concerns the status of a planned review by NEMMCO of NSCS arrangements, required under the Rules.

Revenue treatment of NSCS for TNSPs

As noted above, the efficient delivery of transmission capability by TNSPs requires consideration of all possible options for providing transmission capability. NCSC is one such option. The revenue treatment of network investment under the Regulatory Test has been the subject of detailed revenue, and a robust incentive-based approach has been developed. In contrast, where a TNSP adopts a non-network solution, the costs may be "passed through" to customers as if the cost of the non-network option were part of the TNSP's operating and maintenance costs.

We noted in the Draft Report that network solutions consequently provide a TNSP with the scope to earn a greater return than non-network solutions. This was because of the ability of TNSPs to earn a regulated rate of return on their network capital expenditure, while only being able to pass-through operating expenditures (within which most NSCS would be recovered) at cost. However, we continued, network capital expenditures also carried a risk that the TNSP will earn a reduced return if costs are over-run during that regulatory period. A non-network solution may therefore represent a lower risk/lower return option for a TNSP.

The Electricity Transmission Network Owners Forum (ETNOF)[197] disagreed with this last observation, however.[198] It stated that an TNSP remained legally responsibly for the ability to deliver network services, particularly reliability outcomes. Generation based non-network solutions have inherently lower availability than network solutions, increasing the risk of successful delivery of transmission services. There is a risk that a market counter-party may not meet its contractual obligation, possibly interrupting electricity supply. This potentially carried with it a greater risk than a network solution.

There are risks associated with providing transmission capability using both network and non-network solutions. These risks are understandably different. One depends on a piece of equipment operating as designed while the other relies counter-party meeting a contractual obligation, which in its commercial interest. ETNOF supported further development of incentive arrangements that would recognise the different risk profiles of network and non-network solutions. However, no submission provided any suggestions as to how the Rules could equalise a TNSP's financial incentives between network and non-network solutions.

Stage 2 of our DSP Review is considering this issue. It is looking into how the Rules promote financial incentives for TNSPs when investigating network and non-network options.

NEMMCO's review of NCAS

As noted above, NEMMCO and TNSPs both have some scope for using NSCS under the Rules. There is a degree of ambiguity over where the boundary of respective responsibilities lies and the extent of any obligation on TNSPs to consider NSCS in

---

197 ETNOF is now known as "Grid Australia".

198 ETNOF, Draft Report submission, Congestion Management Review, 3 December 2007, p. 3.

undertaking network planning and/or applying the Regulatory Test. In practice, the current regime could be characterised as NEMMCO acting as "NSCS procurer of last resort". Further ambiguity lies in the appropriate approach for assessing NSCS options against conventional network investment options.

The more efficient use of NSCS as a means of providing transmission capability and changes to TNSP incentives will, over time, contribute to this outcome. However, it is not obvious that the current Rules concerning the roles and responsibilities for NSCS create barriers to this outcome. In any event, NSCS serve a number of purposes, some of which are only very indirectly related to the issue of congestion management.

Hence, while the question of roles and responsibilities for NSCS contracts is clearly an important issue for the operation of the NEM, it would appear to involve issues wider in scope than this Review. These issues should be considered through a separate and more focussed review.

Rule 3.1.4 (a1) of the Rules requires NEMMCO to review and report on the operation and efficiency of spot market for market ancillary services within the overall central dispatch and on the provision of NSCS. Given the possibility of NEMMCO's NSCS review overlapping with the considerations of this Review, NEMMCO sought and received the AEMC's agreement to delay the commencement of its NSCS review until after we published this Review's Draft Report.

We recommended in the Draft Report that NEMMCO should recommence its NSCS review. Accordingly, NEMMCO published a Draft Scoping Paper on a "Review of Network Support & Control Services" in March 2008.[199] In its NSCS review, NEMMCO proposes to cover five areas including: NSCS procurement responsibility and cost recovery; substitutability of NSCS; barriers to market entry of NSCS providers; use and deployment of NSCS; and types of NSCS markets.

NEMMCO released its Final Scoping Paper and finalised the scope of the NSCS Review in early June 2008.[200]

In the context of NEMMCO's NSCS review, the DSP Review Stage 1 Final Report recommended that:

- the AEMC request NEMMCO consider how technical requirements may be modified better to facilitate DSP as a means of providing NCAS as part of its current review of NSCS; and

- the roles and responsibilities for the provision of NSCS between NEMMCO and TNSPs be clarified to ensure that DSP is facilitated.[201]

[199] NEMMCO, "Review of Network Support & Control Services: Draft Scoping Paper", 6 March 2008. Available: http://www.nemmco.com.au/ancillary_services/168-0089.htm.

[200] NEMMCO, "Review of Network Support & Control Services: Final Scoping Paper", 2 June 2008. Available: http://www.nemmco.com.au/powersystemops/168-0097.pdf.

We consider that both components to this recommendation are already included in NEMMCO's NSCS review. NEMMCO is specifically looking at NSCS procurement responsibility.

It is also looking at barriers to market entry of NSCS providers. In its Final Scoping Paper, NEMMCO noted that the ability for parties to participate in tenders for service provision depend on, amongst other things, operational and technical requirements of requested services. These factors can create barriers to entry into the NCAS market.[202] To the extent DSP is restricted by technical requirements, we consider that NEMMCO's review would identify whether there are any possible modifications to facilitate DSP as a means of providing NCAS.

The Reliability Panel is currently undertaking a review of the technical standards in the NEM. This review is looking at the system standards (S5.1a), network performance standards (S5.1), generator access (S5.2), customer access (S.5.3) and MNSPs (S5.3a).[203] We consider that NEMMCO could inform this Reliability Panel review to the extent that its NSCS review identifies possible technical requirements that limit the provision of NCAS from DSP.[204]

C.3.5.3 Final observations

We note that NEMMCO is progressing its review on NSCS. We agree that the scope of the review will cover the key issues around efficient and effective delivery of NSCS in the NEM. We have written to NEMMCO to bring to its attention the final recommendation in DSP Review Stage 1 Final Report about possible technical requirements restricting facilitation of DSP as a NCAS. To the extent NEMMCO identifies technical limitations during its NSCS review, it can inform the Reliability Panel's concurrent review on technical standards.

NEMMCO's current review timetable seeks to release a draft determination report by the end of July 2008. It then intends to publish a Final Determination Report by the end of October. NEMMCO plans to submit to us proposed Rule changes to give effect to its recommendations in its Final Determination Report by the end of 2008.[205]

---

201 NERA, DSP Review Stage 1 Final Report, p.47.

202 NEMMCO, Review of Network Support and Control Services: Final Scoping Paper, 2 June 2008, p.17.

203 AEMC 2008, Reliability Panel Technical Standards Review, Issues Paper, 9 May 2008, Sydney, p.9.

204 The letter we wrote to NEMMCO on this issue is available on the DSP Project Page on our website: www.aemc.gov.au.

205 See NEMMCO website for further information on the review timetable: http://www.nemmco.com.au/ancillary_services/168-0089.htm.

C.4 Risk management instruments

Congestion can give rise to both physical (dispatch) and financial (basis) trading risks. In the Terms of Reference for this Review, we were asked to identify and develop improved arrangements for managing both these kinds of trading risk (as they arise from congestion). This section discusses the management of financial risk. Improvements to the management of physical risk are discussed in section C.2.

C.4.1 Background

In the NEM's regional market within a region there is no price separation, and therefore no basis risk. But generators, large users and retailers contracting across regions do face basis risk.[206] To manage this inter-regional risk, participants make use of financial contracts such as capacity swaps. They can also purchase units to the inter-regional settlement residues (IRSRs) that arise when electricity flows between regions and those regions' prices differ.[207] These IRSR units help fund any hedging contract payment shortfall that arises from inter-regional prices differences.

NEMMCO sells IRSR units every quarter at the Settlement Residue Auction (SRA). At the SRA, auction participants can bid for units up to one year in advance. There are units for every regulated interconnector in the NEM, in both directions. This enables participants to hedge price differences between almost all regions, in both directions.[208]

As discussed in Appendix A, dispatch can sometimes result in "counter-price" flows (i.e. flows from a higher-priced region to a lower-priced region), resulting in negative settlement residues. The current mechanism for funding these negative settlement residues has the effect of reducing the value of IRSR units as an inter-regional hedging instrument: within a billing week negative settlement residues are offset against positive settlement residues for the same directional interconnector. This reduces the availability of positive residues that can be distributed to unit holders.

If there are any remaining negative settlement residues after the netting off, they are recovered from SRA proceeds from the same directional interconnector. SRA proceeds are what participants pay for IRSR units. The importing region's TNSP then receives these proceeds to offset transmission charges. These funding arrangements for funding negative settlement residues can affect the "firmness" of IRSR units as a mechanism for managing inter-regional trading risk.

In this section, we discuss ways in which congestion affects participants' ability to manage their financial inter-regional trading risk. We then discuss and recommend ways to improve the existing hedging instruments to help manage that financial risk.

---

[206] We discuss the relationship between wholesale pricing granularity and basis risk in section C.5.

[207] The value of these residues is equal to the price difference between the regions times the flow between the regions.

[208] Tasmania is connected to the NEM by Basslink, which is a MNSP. Because Basslink is not regulated, there no IRSRs attributed to flows between Tasmania and Victoria.

C.4.2 Improving existing risk management instruments

C.4.2.1 Background

Tools currently available to manage inter-regional basis risk

IRSR units

IRSR units are one of the key tools for assisting participants to manage basis risk in the NEM. IRSR units are a form of Financial Transmission Rights (FTR), and they are auctioned in advance through quarterly (SRAs). [209]

Broadly speaking, the IRSR units associated with a particular "directional interconnector" provide the holder with a share of the positive stream of payments or "residues", equal to the price difference between the two regions joined by the interconnector (in the direction of the directional interconnector) multiplied by the flow on the interconnector (when the flow is in the direction of the directional interconnector). Each IRSR unit relates to a notional 1 MW of the nominal flow limit of the corresponding directional interconnector. For example, if the nominal flow limit on an interconnector is 1000 MW, 1000 IRSR units would be auctioned and the holder of ten IRSR units would receive a flow of payments equal to one per cent of the residues described above.

IRSR units would provide a reliable hedge against inter-regional price differences if a party wishing to trade between two regions could predict with certainty the level and direction of flow on the directional interconnector when there was a price difference between the regions. The *volume* of reliable hedging residue available would depend on the interconnector flow when there was a price difference. For example, if the flow capability at times of price separation was known to be always 1000 MW, trading parties could contract across the region boundary up to this limit and remove any basis risk through the purchase of IRSR units. This known volume might or might not be equal to the nominal interconnector limits used to determine how many IRSR units were sold.

However, in practice, the level of flow capability on directional interconnectors at times of price separation is not known with certainty, for a number of reasons:

- The physical limits of the transmission assets that comprise an interconnector might be temporarily below their normal operating levels due to, for example, maintenance work or weather conditions.

- The flow on a directional interconnector might jointly depend on the output of particular individual generators which make use of the same parts of the network—they are, in effect, competing over a limited amount of capacity. When price separation occurs, the level of interconnector flow would depend on the

[209] FTRs are discussed in more detail in section C.5.

output of these generators (which in turn depends on generator bidding behaviour).

- The relationship between flows on an interconnector, the output of other proximate generators, and constraints on available capacity may be such that the interconnector flows "counter-price" (i.e. from the higher-priced to the lower-priced region).

If any of these outcomes occurs, then the IRSRs accruing in respect of an IRSR unit will not be a firm hedge for an equivalent 1 MW inter-regional contract exposure. In practice, all of these outcomes occur relatively frequently. This is perhaps not surprising when it is recognised that a significant proportion of potential network constraints involve interactions between interconnector flows and the output of individual generators. To predict what interconnector flows will be when these types of constraint bind and drive price separation requires individual trading parties to be able to accurately predict what the output (and hence bidding behaviour) of potentially multiple individual generators will be. This is a very difficult task, and therefore contributes to the lack of firmness of IRSR units.

The possibility of negative settlement residues accruing creates an additional source of reduced firmness of IRSRs. The current Rules stipulate that for each directional interconnector, positive residues can be used (within the same billing week) to net off any negative residues that might occur as a result of counter-price flows. Other things being equal, this will reduce the funds paid out to IRSR holders and therefore reduce the firmness of the hedge. The magnitude of this effect is limited by NEMMCO's current practice of clamping interconnector flows if there is the prospect of negative residues accumulating to a value greater than $6 000. However, while clamping firms the IRSRs in the counter-priced direction by reducing negative residues, it makes no contribution to firmness of the IRSR in the positive-priced direction (i.e. from the lower-priced to the higher-priced region) because when clamped to zero flow, no positive residues can accumulate in the IRSR fund.

Box C.3: Causes of counter-price flows

There are several reasons why a dispatch might cause an interconnector to flow in a counter-price direction:

- Islanding – where a part of the network is physically separated from the rest of the network so that power cannot flow between the two and a counter-price flow is required to support a load in a separate region within the "island". In this case a counter-price flow is likely to be efficient, because the alternative would be load-shedding and a potential exacerbation of the islanding problem.
- Network loops – where a network loop exists that crosses a region boundary such that, by definition, flows along one section of the loop will be in the "right" direction and flows along another section of the loop will be counter-price. The abolition of the Snowy region, which takes effect on 1 July 2008, will remove the most significant inter-regional loop in the NEM.
- Interaction between direct current (DC) and alternating current (AC) interconnectors crossing the same region boundary.
- FCAS constraints – optimising energy and FCAS can result in a counter-price flow, but is likely to be of limited materiality.
- "Dis-orderly" bidding – where a single constraint involves an interconnector flow and a number of individual generators, and those generators are dislocated from the setting of their RRP but are seeking to maximise output at the prevailing regional price. In these circumstance, the generators may bid in a dis-orderly way (e.g. -$1 000/MWh), which in turn might be sufficient to back-off the interconnector flow to such an extent that it flows in a counter-price direction.
- The 5/30 Issue – rapid changes to power flows within a 30-minute trading interval.

Other tools

Participants also make use of financial contracts such as capacity swaps to manage inter-regional risk. This Review has not considered the specific financial contracts available for managing inter-regional risk, as we believe the design of financial contracts is best left to participants in financial markets. However, we do consider the liquidity of financial markets in all our decisions, and we note that participants generally consider financial market liquidity to be adequate in all regions but South Australia.[210]

[210] PriceWaterhouseCoopers, New Perspectives on Liquidity in the Financial Contracts Electricity Markets, Survey November 2006.

C.4.2.2 Discussion

In the Directions Paper we invited views on risk management issues in the NEM. We considered submissions and engaged in bilateral discussions with stakeholders in order to understand better their views on whether and how risk management tools could be improved.

Many participants criticised the existing IRSR instrument for lacking firmness. Snowy Hydro said that IRSR units were imperfect and only supported incremental inter-regional trading (as supported by the Anderson, Hu and Winchester survey). MEU agreed that IRSR units were an ineffectual risk management instrument but raised concerns that fully firm instruments (such as firm FTRs) could lead to higher costs for consumers. NEMMCO agreed that IRSR units could be made firmer by funding negative settlement residues in some way, perhaps based on the FTR model. The NGF also supported making changes to the SRAs that could "firm-up" IRSR units. In particular, the NGF advocated recovering all negative settlement residues from auction proceeds, in place of the current Rules in which negative residues are netted off against positive residues within each settlement week. The Southern Generators agreed that the current arrangement ought to be changed.

It was clear that the lack of firmness provided by IRSR units could reduce parties' willingness to trade inter-regionally and thereby detract from the liquidity of contract markets, in terms of volumes of contracts and numbers of contracting parties. Though very difficult to quantify the impacts of increasing IRSR firmness on inter-regional trade, it was reasonable to infer that improvements to the effectiveness of the hedging instruments would lead to greater inter-regional trading.

Against this background, we considered measures to firm up IRSR units and to improve the design of the SRAs.

Firming up IRSR units

We assessed three broad approaches to firming up IRSR units and therefore improving them as an inter-regional hedging instrument:

- improving the reliability and predictability of the underlying network;
- amending the arrangements for *managing* negative settlement residues; and
- amending the arrangements for *funding* negative settlement residues.

Improving the reliability and predictability of the transmission network

The need for instruments to manage basis risk arising from inter-regional trading reflects the possibility that prices between regions will separate. This occurs primarily as a result of network constraints binding. The likelihood of network constraints binding is, in turn, influenced by the transfer capability of the underlying physical transmission assets and how those assets are operated at any given time.

Improving the reliability and predictability of the transmission capability derived from the underlying physical network and how it is operated, is an important factor in firming up IRSR units. If participants could accurately predict interconnector transfer limits, then they could determine with a high degree of certainty the number of IRSR units necessary to hedge an inter-regional position.

Many improvements have recently been made or are in the process of being implemented that should improve the reliability and predictability of interconnector transfer capability. These include the Chapter 6A Transmission Revenue and Pricing Review, the LRPP, the new process and economic criteria for region change and the Rule Determination to abolish the Snowy region.

In addition, the AER has developed the "Service Target Performance Scheme" designed to provide incentives for TNSPs that relate directly to increasing the provision of transmission capability at times when it has most value to the market, i.e. when constraints are binding. This work is focused on improving the incentives for TNSPs in how they manage and schedule network outages. We discuss this scheme in more detail in section C.3. The importance of this work is supported by our findings that the incidence of outage-caused constraints is increasing (see Appendix B). This scheme will potentially make an important contribution to the firmness of IRSRs.

There are also several prospective measures that might influence the provision of inter-regional transfer capability, and by extension the firmness of IRSR units. The most significant of these measures is the direction we received from the MCE to develop a framework for a NTP. In our Draft Report we recommend that the NTP will have responsibility for reporting on network capability as part of it NTNDP, which will provide an additional information resource for participants. We discuss this in more detail in section C.3.4.

This package of recent and ongoing reforms are likely to significantly improve the reliability and predictability of interconnector transfer limits. This combined with the recommendations in this Review to make more transparent predictable NEMMCO's process for invoking and revoking constraints (see dispatch) and to develop a Congestion Information Resource that will give participants more information to help them understand how the network's available network capability may change due to planned network events like outages.

Managing negative settlement residues

The firmness of IRSR units can be reduced by negative settlement residues. Negative settlement residues occur when constraints bind in such a way that: (a) there is a price separation, and (b) a flow on a directional interconnector is in a counter-price direction.

There are two separate effects at work. First, at times of counter-price flows, positive residues are not accumulating on the directional interconnector from the lower-priced to the higher-priced region. Second, positive residues that would otherwise be payable to holders of units in the directional interconnector going the other way, may be used to fund the negative residues (in the same billing week). Hence, the IRSR units may be made less firm in both directions of an interconnector by a single incident of negative residues accumulating.

NEMMCO currently manages the accumulation of negative settlement residues by "clamping" or restricting flows between regions, to limit the accumulation. We discuss this in more detail on section C.2.

Funding negative settlement residues

How the prospect and incidence of negative settlement residues are managed can influence the firmness of IRSR units. The current arrangements, in addition to limiting the incidence of negative settlement residues by allowing NEMMCO to intervene in the physical dispatch (clamping), fund any residual negative residues in two ways:

- If there are positive residues on the same directional interconnector in the same billing week as the negative residues, the positive residues are used to net-off the negative residues.
- Any negative residues that remain after netting-off within the billing week, are funded from the proceeds of the next auction(s) for that directional interconnector.

When we made the Rule[211] on 30 March 2006 enabling negative residues to be funded from auction proceeds, we included a three-year sunset clause in order to clearly signal our intention that this was not to be a long-term response to the negative settlement residue issue. Instead, our intention was always to examine the issue more thoroughly in the context of this Congestion Management Review.

In the Draft Report we proposed three options for improving the funding of negative settlement residues and asked for participants' feedback on them:

- netting-off against positive residues in the same billing week;
- directly billing the importing region's TNSP; and
- using an external source of funds, namely generators.

[211] AEMC 2006, National Electricity Amendment (Negative Inter-Regional Settlements Residue) Rule 2006, Rule Determination, 30 March 2006, Sydney.

Box C.4: Netting-off against positive residues in the same billing week

Our analysis of netting-off from the same directional interconnector fund suggests that netting-off within a billing week is in many ways equivalent to recovery via auction fees. In effect, a negative residue netted-off within a billing week represents an additional *ex post* "fee" (equal to the positive settlement residues foregone) borne by the purchasers of IRSR units.

The difference between netting-off and explicit recovery from auction fees is that the latter approach recovers the shortfall from future auction fees, while netting-off in effect increases the auction fee paid by the current holders of IRSR units. Allowing negative settlement residues to reduce the value of currently-held IRSR units would tend, other things being equal, to reduce the value of IRSR units for hedging purposes. This would presumably be reflected in the prices participants are willing to pay for IRSR units in the SRAs. Given that the "importing" TNSPs' load customers are ultimately the beneficiaries of both SRA fees and proceeds from lower TUOS charges, they would therefore ultimately incur the cost of funding negative residues irrespective of which of the two ways this occurred.

A majority of submissions to the Draft Report supported this recommendation.[212] ERAA and Macquarie Generation said it would increase certainty of the residues and enhance the SRA process.[213] They also considered it would reduce the risk of inter-regional hedging and increase competition in the various forward contracts in the NEM. Macquarie Generation also stated that the increased interest in IRSR units could contribute to higher auction proceeds to fund negative settlement residues.[214] NEMMCO said it could implement this recommendation by modifying its Market Management System.[215]

The EUAA did not support the recommendation. It preferred to retain the current arrangements, which have only been in place for the last 18 months, until the full impact of those changes was known.[216]

---

[212] CS Energy, Draft Report submission, pp.1-2.; NGF, Draft Report submission, pp.6-7; TRUenergy Draft Report submission, p.2; Origin Energy Draft Report submission, p.1; Hydro Tasmania Draft Report submission p.2.

[213] ERAA Draft Report submission, p.3; Macquarie Generation Draft Report submission, p.2.

[214] Macquarie Generation Draft Report submission, p.2.

[215] NEMMCO Draft Report submission, p.1.

[216] EUAA Draft Report submission, p.20.

Box C.5: Directly billing the importing region's TNSP

The question of whether it is appropriate for an importing region's customers to be entitled to SRA proceeds is a matter that was touched on but not addressed in our review of transmission pricing arrangements in 2006[217]; we considered it a matter requiring jurisdictional advice. It appears reasonable however, for negative settlement residues to be recovered from the importing region's TNSP. This is because loads in an importing region can benefit from the counter-price flow that led to the negative settlement residues in the first place, in that the counter-price flows may have led to a lower RRP in the importing region than would otherwise have been the case. This is consistent with the existing practice of recovering net negative Settlement residues from the importing regions SRA proceeds. In this context, an alternative to recovering negative settlement residues from SRA proceeds may be for NEMMCO to charge the importing region's TNSP for them directly. This could improve the transparency and certainty of the recovery process. We also note that, from a practical perspective, a mechanism for NEMMCO to charge negative settlement residues to a TNSP exists under the Rules already—the mechanism relates to instances when IRSR units are unsold.

Box C.6: Using an external source of funds, namely generators and "positive flow clamping" (PFC)

We assessed these options, discussing them in detail at a workshop in January 2008, but decided against recommending them for implementation as part of this Review. For a full discussion on these alternatives, see section C.4.4.

In the Draft Report, we recommended that negative settlement residues (a) should no longer be netted-off against positive residues within a billing week, and (b) should be funded by directly billing the importing region's TNSP.

We asked stakeholders for their views on this recommendation, in particular from TNSPs as to whether it raises any issues for the price-setting and revenue recovery procedures under Chapter 6A of the Rules.

The majority of submissions supported the recommendation. CS Energy, Origin Energy, Hydro Tasmania, Stanwell, Tarong Energy, InterGen, and the NGF all considered these recommendations would improve the firmness of IRSR units, which would therefore enhance their value as an inter-regional trading instrument. The EUAA supported the proposal in principle, but wanted more information. It

[217] AEMC 2006, National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22, Rule Determination, 21 December 2006, Sydney.

emphasised that the recovery of negative residues should be carefully aligned with the offset of settlement residues.[218]

NEMMCO sought further information about implementation.[219] ETNOF drew attention to the possibility that TNSP funding negative settlement residues could lead to volatility in transmission charges; transmission charges would need to take account of the transfers of settlement residues and auction proceeds.[220]

Macquarie Generation disagreed with the second part of the recommendation, arguing that it should be the *exporting* TNSP that funds negative residues caused by dis-orderly bidding, and suggesting that this would act as an incentive for TNSPs to address the underlying congestion problem.[221] It supported the first part of the recommendation.

These recommendations all seek to improve the usefulness of the IRSR unit as a hedging instrument for generators, retailers and large users. The first recommendation to change the funding of negative settlement residues will remove the potential for the value of IRSR units to be diluted because of incidents of negative settlement residues. It will also remove an arbitrary distinction in the Rules between funding negative settlement residue which occur in the same billing week as positive settlement residues, and those which do not. By removing this intra-week netting off, unit holders will retain the full value of residues accumulated during other events during a week, improving the IRSR as a risk management instrument.

Directly billing the relevant TNSP, who will then recover these costs through charges to its customers, is a more direct and transparent way to recover negative settlement residue than via auction proceeds, as is currently the practice – although the net impact is broadly the same. This arrangement provides NEMMCO with the flexibility to recover negative settlement residues in a timely manner rather than being limited by the timing of auctions every quarter.

These changes, coupled with an increase in the dispatch intervention threshold to manage the accumulation of negative settlement residues, will improve the value and usefulness of the IRSR unit as a mechanism for managing inter-regional basis risk, while also noting that it will increase transmission charges to customers. The net effect to customers is not known.

SRA design

We also considered incremental improvements to SRA design, to improve their flexibility and hence their usefulness. Options included longer- and shorter-dated IRSR units, peak and off-peak IRSR units, and the sale of some units further in advance.

---

[218] EUAA Draft Report submission, p.20.

[219] NEMMCO, Draft Report submission, p.2.

[220] ETNOF Draft Report submission, p.5.

[221] Macquarie Generation submission, p.3.

We considered that the option to sell units further in advance had merit. The benefits of the other options obtained by repackaging the existing SRA product, would be done by market participants themselves or by financial intermediaries.

In the Draft Report, we therefore recommended extending from 12 to 36 months the lead-time between when the IRSR units are auctioned and when they apply. In other words, participants will be able to buy some IRSR units up to three years in advance rather than only one year in advance. Furthermore, we considered the Settlement Residue Committee (SRC) would be the most appropriate group to determine the size of each tranche of units available for auction. but we would expect that the majority of units will still be reserved for the nearer-term auctions.

Auctioning some IRSR units further in advance should make them more useful to participants who are seeking to plan and hedge their longer-term contract positions. It will provide further options for participants when structuring their long-term portfolio, and for secondary trading. We note also that there will be negligible downsides to implementing this proposal: implementation costs will be minimal; and any units that are available for sale three years in advance but are not sold, will be made available in the nearer-term auctions.

The majority of submissions to the Draft Report supported this recommendation.[222] EUAA noted that it would assist in the active management of basis risk, increase the flexibility for retailers to align contract term and price with minimal implementation costs, and support long-term portfolio management.[223] Two submissions commented that it would increase market liquidity of electricity derivatives.[224] Macquarie Generation stated that it would allow participants to develop further financial products in the secondary IRSR market.[225] CS Energy noted that it would improve price discovery of IRSRs and complement the current liquid period of vanilla contracts.[226] There was also support for the recommendation that the Settlement Residue Committee should determine the specifics of this proposal.[227]

On the other hand, ETNOF was concerned if selling units three years out would also require TNSPs to forecast events, like outages, that could affect interconnector capability three years out also. ETNOF stated such long term forecasting to poor forecasting with almost arbitrary assumptions.[228] Moreover, CS Energy noted that

222 ERAA, Draft Report submission, p.3; Macquarie Generation, Draft Report submission, p.4; Snowy Hydro, Draft Report submission, p.2; EUAA, Draft Report submission, p.23; CS Energy, Draft Report submission, p.3; InterGen, Stanwell and Tarong, Draft Report submission, p.2; Origin Energy, Draft Report submission, p.1.

223 EUAA Draft Report submission, pp.3, 23.

224 Snowy Hydro, Draft Report submission, p.2; InterGen, Stanwell and Tarong Energy, Draft Report submission, p.2.

225 Macquarie Generation, Draft Report submission, p.4.

226 CS Energy, Draft Report submission, p.3.

227 Hydro Tasmania, Draft Report submission, p.2.

228 ETNOF, Draft Report submission, p.4.

IRSRs projected further into the future have uncertain value, and therefore proposed that the volume of IRSRs auctioned be weighted to the near term.[229]

The redesign of the SRA to sell units up to three years in advance would improve their flexibility and usefulness for participants seeking hedge cover for their longer term contract positions. It will potentially make secondary trading more likely, and thereby improve liquidity in the range of risk management tools available in the NEM. The issues raised by submissions are more implementation issues and are to be discussed below.

C.4.2.3 Final recommendations and implementation

Our final recommendations affirm the draft recommendations. That is, we propose to improve the arrangements for managing and funding negative settlement residues, and to improve the design of the IRSR unit and of the SRA at which the IRSR units are sold. These recommendations will improve the firmness and usefulness of IRSR units as an inter-regional hedging instrument.

We are also recommending changes to the way NEMMCO intervenes in dispatch to prevent or limit counter-price flows including improving the predictability and transparency of NEMMCO's intervention and increasing the intervention threshold from \$6 000 to \$100 000. See section C.2 for more information on these recommendations and their implementation.

Firming up IRSR units

We propose amending the Rules to change how negative settlement residues are funded, we recommend that all negative settlement residues should be recovered directly from the importing region's TNSP.

Implementation

This new recovery method replaces NEMMCO's current practice of netting-off negative settlement residues against positive settlement residues within a billing week (Method 1) and then recovering any outstanding negative settlement residues from SRA proceeds (Method 2). Therefore, the *Draft National Electricity Amendment (Negative Inter-regional Settlements Residue Amounts) Rule 2008* (Negative Residue Draft Rule) deletes both Method 1 and Method 2 from the Rules and replaces them with this new recovery method (clause 3.6.5(a)(4)).

In a submission to our Exposure Draft[230], NEMMCO expressed concern that it may not have sufficient funds to finalise settlement should a TNSP be late with or not make payment to cover outstanding negative settlement residues. To address this, clause 3.6.5(a)(4) of the Negative Residue Draft Rule now allows NEMMCO to determine a different payment interval for the recovery of negative settlement

229 CS Energy, Draft Report submission, p.3.

230 NEMMCO, Exposure Draft submission, 15 April 2008.

residues from a TNSP in order to recover funds in advance of the normal settlement day.

NEMMCO also stated that in some circumstances it may be difficult to determine who is the appropriate TNSP in each region to be responsible for the payment of negative settlement residues. We recognise that this may be a problem and have amended the Negative Residue Draft Rule to ensure that this is resolved. Clause 3.6.5(a)(4B) of the draft Rule now provides the AER with the power to make (and amend) a determination on this issue. We consider the AER is the appropriate body to do this, given that it sets the TNSP revenue determination and therefore has all the necessary information to determine which TNSPs' customers benefit from negative settlement residues.

Should there be any unrecovered negative settlement residues at the time of the proposed Negative Residue Draft Rule's commencement, a savings and transitional provision enables NEMMCO to recover those residues using the method in operation at the time the residues were incurred, i.e. Method 2.

The current arrangement with inter-regional TUOS (which is due to expire on 1 January 2009) is unaffected by the new method.

SRA design

We recommend making several tranches of IRSR units available for auction up to three years in advance of the relevant IRSR quarter, with the SRC detailing the release profile of the units.

Implementation

This will be a change to the process of auctioning units under the SRA.

There are three key steps to implement this recommendation. The first is for the SRC to agree on the designs of units for auction three years out. The second is Rules consultation on the ammended Settlement Residue Auction Rules. The third is Software development in the SRA engine and interface.

Clause 3.18.3(a) of the Rules requires NEMMCO to develop "auction rules", which must include the procedures for conducting auctions and the timing of auctions.[231] Clause 3.18.3(d) enables NEMMCO to amend the auction rules at any time with the approval of the SRC. Clauses 13.8.3(e) and (f) identify the consultation process for amending the auction rules.

The process of extending the auctioning of IRSR units out three years is a procedural matter for NEMMCO and the SRC to consider. As such, and following discissions with NEMMCO, no amendment to the Rules is necessary to implement this change.

---

[231] The Auction Rules, and additional information on the SRA, are available on NEMMCO's website at: http://www.nemmco.com.au/settlements/settlements.htm.

In considering the recommendation, the SRC should have regard to submissions made to this Review's Draft Report. In particular, it should consult with participants on how it should auction off the new tranches of units. For example, should it decide to auction an equal number of units each quarter or should it gradually offer more units as the auctions get closer to the relevant quarter?[232]

On a related matter, NEMMCO identified that in June 2008, it will start auctioning units for Q3 2009 (July- September 2009). The current negative settlement residue recovery mechanism is due to expire on 30 June 2009. In our view it would be inefficient to consider reverting to the old recovery mechanism of auction fees when we are recommending a variation of the existing recovery mechanism. Therefore, it would be appropriate to extend the current sunset until the recommended recovery mechanism could be implemented. This would promote a smooth transition between the current and recommended new recovery mechanism. We could give effect to this in the form of a savings and transitional provision in the related Rule on funding of negative residues discussed above.

C.4.3 Negative settlement residues: alternative funding arrangements

Two options for improving the funding of negative settlement residues were proposed in the Draft Report which, after assessing, we decided not to develop as firm recommendations for change in the context of this Review:

- positive flow clamping; and
- generator funding.

In light of the PFC workshop held in January 2008 (discussed below), we have further considered the Gatekeeper and CS Energy generator funding options. The following sections present these option and discuss our view on these alternatives.

C.4.3.1 Positive Flow Clamping

This section considers PFC as an alternative to "zero flow clamping" in cases where binding constraints create incentives for generators to bid in a dis-orderly manner, resulting in counter-price flows. PFC works by clamping the relevant interconnector to a positive flow (in the direction of the lower priced region to the higher priced region), rather than clamping to zero flow as is the current practice. The main benefit of PFC compared with conventional clamping is that positive IRSRs continue to accumulate following the intervention, thus improving the firmness of IRSR units.

The concept of PFC was raised in a generic manner in the Directions Paper, as an option that would confer priority to interconnector flows in the event of a constraint that limited both intra- and inter-regional flows. Both Macquarie Generation and Snowy Hydro supported this option. Macquarie Generation said that it would be possible to implement a discretionary constraint to fully restore interconnector flow

[232] CS Energy, Draft Report submission, p.5.

and ensure positive residues where pre-dispatch was showing likely counter-price flows caused by dis-orderly bidding behaviour. Another alternative would be to provide for a sharing of the available transmission capacity between "local remote" generation and interconnector flows based on some form of pro-rating. Macquarie Generation also considered that either a full interconnector priority option or some kind of a sharing approach would provide a sharper locational signal for new generation investment. Snowy Hydro advocated the same proposal as an alternative to a CSC/CSP or Constraint Based Residue (CBR) approach to managing congestion.[233] Snowy Hydro saw advantages in eliminating negative settlement residues (without clamping) and maximising the usefulness of IRSR units for inter-regional trading.

NEMMCO expressed support in general for less complex and uncertain alternatives to clamping, but had several reservations about the specific proposal of PFC, including: (1) a possible conflict with the MCE position to use "fully optimised constraint formulation"; (2) the option could increase the economic cost of dispatch; and (3) that a number of practical implementation issues would require resolution.

Through our Draft Report, we decided to explore the potential benefits (and implementation issues) of the PFC option further and therefore specified the following high-level framework to facilitate consultation:

- PFC would be considered only for counter-price flow events that are caused by generators' incentives to bid below avoidable cost due to constraints binding that create a disjuncture between dispatch and settlement at the RRP. Such events would be pre-defined and identified by constraint equations.

- PFC would be invoked when negative residues caused by one of the defined constraints were forecast to accumulate to $6 000.

- Under PFC, the interconnector would be clamped to the flow at which that interconnector was dispatched in the dispatch interval just prior to the PFC invocation, if that flow was in the direction of lower-priced region to higher-priced region.

- If the interconnector turns counter-price or was already flowing counter-priced prior to PFC being invoked, the default arrangements for managing counter-priced flow (i.e. clamping to zero MW) would apply.

In the Draft Report we also made the following initial observations of the impact of PFC. A more detailed explanation of the proposed PFC design can be found in Appendix E.

Effect on IRSR firmness

We considered that PFC would improve the firmness of IRSR units relative to zero flow clamping. This is because under PFC, the interconnector would be constrained

---

[233] These approaches are discussed in more detail in section C.5.

at a non-zero level in the positively priced direction, which would result in the accumulation of IRSRs, whereas under the current clamping regime, no IRSRs accumulate.

Firming-up IRSR units would, other things being equal, encourage more participants to use this product to hedge basis risk (as opposed to using the IRSR product for speculative purposes). This could promote inter-regional contract trading, although it is difficult to assess the likely magnitude of this impact. IRSR units would still not be fully-firm and the returns would still be unpredictable due to other factors influencing the flow at which the interconnector constrains, such as generator behaviour and variations in transmission capability. The question is thus by how much PFC would improve firmness and to what extent would it enhance inter-regional trade.

Effect on dispatch

PFC would result in a different dispatch outcome to the current clamping regime. Intra-regional generators[234] would be backed off to a greater extent, while inter-regional generators would generate more.

In the presence of transient market power, it is not possible to analytically determine the dispatch efficiency effects of PFC based on dispatch bids and offers alone. However, in a price-taking environment, it could be argued that PFC would often improve dispatch efficiency. This is based on the presumption that dispatch was efficient before the conditions for dis-orderly bidding and counter-priced flow were established. If this were the case, then PFC would maintain dispatch broadly in line with that efficient outcome, whereas clamping to zero MW or allowing the negative residue to accrue from a counter priced flow may be more likely to result in a move away from efficient dispatch.

System security

We do not believe that PFC would create issues for the management of system security. PFC and clamping both involve NEMMCO retaining the same level of control over the same variables in the dispatch. Hence, both would appear consistent with the secure operation of the power system. Neither intervention would be invoked if to do so would compromise system security. PFC and clamping would be discretionary interventions for NEMMCO to apply under the Rules (subject to consultation, publication and compliance with appropriate guidelines).

Constraining-on interconnectors has the potential to result in generators in the importing region being dispatched below technical limits. However, this is considered unlikely because dispatch would not be expected to vary significantly under the approach described above.

234 Those generators with coefficients in the relevant binding constraint equation.

Dynamic efficiency effects

Placing further constraints on the intra-regional generation contributing to congestion may enhance incentives to manage that congestion in the following ways:

- create incentives for more efficient generator locational decisions; and
- create incentives for affected generators to find innovative ways, possibly in conjunction with TNSPs, to reduce the frequency and duration of constraints leading to negative settlement residues.

Financial market competition and liquidity

While PFC should increase the willingness of generators to enter contracts with counter-parties in other regions, it may, by increasing dispatch risk, reduce the willingness of generators to enter contracts within their own regions. Analytically, it is difficult to say whether the volume of contracts offered in a given region would increase or decrease as a result of PFC. However, firmer IRSR units would, at the margin, improve the ability of parties from other regions to offer contracts at a particular RRN. Hence, the number of parties offering contracts at a particular RRN may increase.

Participants' responses

Submissions to the Draft report were generally unsupportive of the introduction of PFC. While few submissions supported the introduction of PFC as a means of instilling firmness in IRSRs, a number of submissions felt that further detailed work to investigate how it would be implemented was necessary[235]. In particular, the EUAA considered that while PFC may be beneficial, further work was necessary to consider its impact on dispatch efficiency and IRSR firmness. However, Macquarie Generation recognised that a PFC approach would provide locational signals for generation investment and would create incentives for TNSPs and generators to work together to reduce intra-regional congestion.[236]

Most submissions were concerned about the choice of clamping threshold.[237] The choice of a fixed threshold would be arbitrary and many participants agreed with the concerns about this option that were noted in the Draft Report. A dynamically determined threshold would mean that it was not predictable and would therefore increase uncertainty. Submissions also noted that the outcomes of the dispatch process would potentially be more complex and unpredictable.[238] Some submissions argued that it would increase both the cost of generation and

---

[235] Snowy Hydro, Draft Report submission, p.2, EUAA, Draft Report submission, p.22, Macquarie Generation, Draft Report submission, p.4, NEMMCO, Draft Report submission, p.1.

[236] Macquarie Generation, Draft Report submission, p.4.

[237] ERAA, Draft Report submission, p.4, CS Energy, Draft Report submission, pp.2-3, TRUenergy, Draft Report submission, pp.4-5.

[238] Snowy Hydro, Draft Report submission, p.2, Origin Energy, Draft Report submission, p.1.

transmission losses.[239] These submissions thought that PFC would lead to inefficient dispatch and would not materially increase market liquidity. Concerns were raised that PFC might create perverse incentives for generators and increase technical complexity into the dispatch process.[240]

NEMMCO considered that PFC seemed unable to be applied proportionately to changing market conditions. NEMMCO was also concerned about the implied underlying assumption that when a particular constraint binds, that it will always result in non-cost reflective bidding. [241]

The Stanwell, Tarong and InterGen submission considered that introducing PFC is likely to result in a reduction of dispatch efficiency with limited benefits with respect to market liquidity. They do not recommend the adoption of PFC and consider that the Draft report recommendations relating to risk management should be further developed. These generators based their analysis on work commissioned by EnergyEdge Consulting.

The EnergyEdge report provided an assessment of PFC as a means of reducing negative settlement residues, firming up IRSR units and increasing competition and market liquidity. EnergyEdge conducted a high level historical analysis using QNI residues as a case study. It found that PFC was unlikely to impact materially upon the risk profile of an IRSR unit.[242] Its results showed that PFC will only resolve a small portion of the basis risk with IRSR units and is not expected to result in any material change in the level of inter-regional trading by those entities. It therefore concluded that PFC will not have a material impact on market liquidity.[243]

EnergyEdge stated that the three-year SRA process, allocation of negative settlement residues to TNSP and reforms to improve reliability and predictability of interconnector transfer limits would deliver greater benefits for market liquidity, with less direct intervention in the physical market, compared to the introduction of PFC. Energy Edge stated that these arrangements improved risk management tools, transparency and predictability without the need for physical intervention.[244]

A larger group of generators[245] engaged ROAM consulting to conduct further analysis. ROAM conducted market simulations and detailed load-flow modelling to understand the market and efficiency impacts of PFC. Its analysis found that the application of PFC would lead to decreases in market efficiency. ROAM found that

---

239 InterGen, Stanwell and Tarong Energy, Draft Report submission, p.3, CS Energy, Draft Report submission, p.2.

240 ERAA, Draft Report submission, p.4.

241 NEMMCO, Draft Report submission, p.3.

242 Energy Edge 'Positive Flow Clamping Review', p.5.

243 Energy Edge 'Positive Flow Clamping Review' p.51.

244 Energy Edge 'Positive Flow Clamping Review', p.5.

245 CS Energy Ltd, InterGen Australia, NewGen Power, Stanwell Corporation Ltd and Tarong Energy Ltd.

PFC would result in an increase in transmission system loss and total generation costs. These, in turn, would lead to an increased market pool price. [246]

The NGF, in contrast, was opposed to using any form of clamping as a solution. Its view was that the most efficient way to address negative settlement residues is to allow the market to operate without clamping. The NGF stated that the most appropriate response is to separate the funding and market dispatch issue. It proposed that funding negative settlement residues through uplifts to either wholesale or transmission prices, or charged to generators.[247]

C.4.4 Generator funding of negative settlement residues

We discussed this option in the Draft Report. This funding option supplements the accumulated residues payable to IRSR unit holders using with an additional source of funding. Externally funding negative settlement residues is a limited form of firming up the IRSRs. The principle could be applied more extensively, at the extreme by making IRSRs 100 per cent firm by funding any shortfall due to network limitations or negative settlement residue through some form of customer uplift. While this would substantially reduce inter-regional trading risk, we think that the cost to customers would be prohibitive and would represent a major policy change to how the NEM operates. We did not, therefore, develop the option any further in the Draft Report than in the Directions Paper.

The exception to this position relates to our observations around the possibility of Rule-based arrangements in which individual generators or groups of generators elect fund negative settlement residues themselves as a means of avoiding NEMMCO clamping interconnector flows. The CS Energy proposal discussed below in section C.4.4.4 is a form of this option.

An example drawn from Southern Queensland illustrates this type of arrangement. Under the current Rules, generators in Southern Queensland face the risk of being constrained-off through clamping when there are negative residues. This can occur even where they may be the least-cost plant to serve load in NSW. This can occur when the Tarong constraint (within Queensland) binds, the RRP is relatively high, and the Southern Queensland generators submit low-priced bids in an attempt to be dispatched. This can result in the interconnector could be dispatched in a counter-price direction.

If the risk of being constrained-off were a sufficiently material problem for the Southern Queensland generators, they might in some circumstances prefer NEMMCO not to clamp, and choose to fund the negative residues themselves. In other words, interconnector flows would continue to be counter-price, but the intra-regional generators would pay into the IRSR fund the difference between the (higher) exporting region price and the (lower) importing region price. These generators would effectively receive the importing region's RRP on the proportion of their output that contributed to the counter-price flows. This would make the IRSRs

[246] ROAM Consulting 'Investigation of Positive Flow Clamping' p.17.

[247] NGF, Draft Report submission, p.7.

as firm as they would be under clamping, but would avoid the need for a physical intervention in the dispatch.

In our view, there were substantial implementation issues to resolve in developing the detail of such an option given that it is a form of location-specific congestion pricing (see section C.5 for a discussion on these implementation issues). We therefore questioned whether such an intervention was warranted given the materiality of the issue potentially being addressed. On the other hand, we could see its potential merit if it could be implemented in a transparent and non-discriminatory manner, and if it obviated the need for physical interventions in dispatch, having regard to the views of market participants on the undesirable effects of clamping. In the Draft Report we therefore sought views from stakeholders as to whether such a proposal was practical and/or warranted.

Participants' responses

Views were split as to whether generators ought to fund negative settlement residues. ERAA supported the proposal in principle but required further detail.[248] Origin Energy supported participant funding of negative residues but only as a "second-best" approach.[249] The benefit of this approach over clamping, Origin Energy considered, was that it would reduce the risk to generators caught behind temporary constraints. ERAA suggested that funds from generators bidding negatively behind a constraint could be used to fund negative residues caused by their dispatch.[250] TRUenergy also had no objections to generators voluntarily funding negative residues to avert zero clamping. While recognising the unlikelihood of such an arrangement arising, TRUenergy proposed that generators could arrange a bilateral agreement with NEMMCO.[251]

EUAA did not support the proposal for generators to fund negative settlement residues, arguing that it could be administratively complex, may lead to gaming, and may lead to inconsistency across the market.[252] Hydro Tasmania also rejected the proposal on the grounds that it was not clear how the set of eligible generators would be defined or whether it would force non-optimal NEMDE outcomes on all regulated interconnectors.[253]

CS Energy indicated their support for this proposal, provided that the Rules are simple.[254]

[248] ERAA, Draft Report submission, p.3.

[249] Origin Energy, Draft Report submission, p.3.

[250] ERAA, Draft Report submission, p.3.

[251] TRUenergy, Draft Report submission, p.2.

[252] EUAA, Draft Report submission, p.21.

[253] Hydro Tasmania, Draft Report submission, p.3.

[254] CS Energy, Draft Report submission, p.3.

C.4.4.2 Positive Flow Clamping Workshop

We held a Positive Flow Clamping workshop in January 2007 to discuss in more detail PFC and the other funding alternatives.[255] This section discusses the views expressed at the workshop on PFC and presents our reasoning not to consider the option further in the context of this Review. In the following sections, we consider the participant alternatives also discussed at the workshop, and present our considerations on those alternatives.

Issues with PFC

At the workshop, participants expanded on the issues raised in their Draft Report submissions. These are discussed above in section C.4.3.1.

One particular issue raised at the workshop was the level of intervention and discretion required by NEMMCO. NEMMCO noted some of the difficulties that it may have when implementing PFC. It expressed concern that it may be required to either make a judgement about a participant's costs and bidding strategies, or to make a judgement when classifying pre-defined constraints. Other participants were also concerned that NEMMCO may need to exercise greater discretion than is presently the case on the timing and extent of the intervention.

Considerations

We discuss the benefits of PFC above in section C.4.3.1. In summary, we see PFC as an option for improving the firmness of IRSR units relative to their firmness under zero flow clamping.

However, PFC is only a partial solution. It only addresses the situation where negative settlement residues result from dis-orderly bidding. In addition, in the presence of strategic bidding, it is difficult to determine analytically what the dispatch efficiency benefits may be.

Importantly, PFC will increase the level of NEMMCO discretion in dispatch. One of the reasons zero flow clamping is a problem is because it requires NEMMCO use its discretion to intervene in dispatch. By increasing NEMMCO's level of discretion further, PFC is unlikely to improve market efficiency and might increase the general perception of dispatch risk.

For these reasons, we are not recommending PFC as an alternative to zero flow clamping in this Review.

At the PFC workshop two alternatives to PFC were introduced. TRUenergy suggested that we consider the Gatekeeper scheme, originally investigated by NEMMCO in 2003, while CS Energy proposed another option for the funding of negative residues by generators. While these provide an alternative to clamping that

[255] For more information on the workshop, go to: "Positive Flow Clamping Workshop" http://www.aemc.gov.au/electricity.php?r=20080118.163655.

may reduce the level of intervention in the dispatch process, there are a number of design and implementation issues that would need to be considered in order to consider participant funding of negative settlement residues. The alternatives are discussed below.

C.4.4.3 Gatekeeper proposal

At the PFC workshop (and in its Draft Report submission) TRUenergy proposed the Gatekeeper scheme as an alternative to PFC. Gatekeeper was originally investigated by NEMMCO in 2003.[256]

Proposal objective

The objective of this option is to provide incentives for a "gatekeeper" generator to improve interconnector efficiency, thereby increasing the quality of IRSRs.

Proposal description

This proposal pre-defines the relative shares of access to a RRN held by an IRSR unit holder. This option allocates to a "negative gatekeeper" generator, a "natural volume", which is equal to the difference between the constraint limit and "k", where "k" is a selected "natural volume" of flow on the interconnector. If the generator produces electricity to a level that constrains the interconnector flow below "k", then the generator compensates IRSR unit holders, thereby removing the dis-orderly bidding incentives for the generator. Where the generator produces electricity to a level below their natural volume, the generator is rewarded with the additional settlement residue. The scheme also provides a form of "constrained-on" payment to "positive gatekeeper" generators, where increased generation increases an interconnector flow thereby increasing the quantity of settlement residue.

Benefits

TRUenergy identified a number of benefits from this scheme:

- there is no need for a constraint to be applied and there is therefore no need for involvement by NEMMCO and no unpredictability;
- optimal dispatch is guaranteed as generators are priced, at the margin, accurately to their coefficient in the constraint equation. Dis-orderly bidding is not rewarded;
- generators and holders of IRSR units know with certainty, in advance, what proportion their settlement will be relative to the various regional prices. It therefore increases the firmness of the IRSR units; and

[256] CRA, "Dealing with NEM Interconnector Congestion: A Conceptual Framework", 24 March 2003. A copy of this report can be found on the MCE website : www.mce.gov.au.

- while counter-price flows are possible, they are funded by the gatekeeper generators;

NEMMCO noted at the workshop that this option was likely to be simpler to implement than PFC because it was operationally similar to the trialled CSP/CSC mechanism in the Snowy region and would not rely on direct market intervention or discretion by NEMMCO.

Issues

There are a number of outstanding issues that would need to be considered in order to implement this alternative method for funding negative settlement residues:

- How would the proposal determine which generator is dispatched? It is suggested that this may be based on the generator's associated coefficient in the constraint, or proportionally on the generator's market share.

- What are the consequences of dispatch being on a 5-minute basis while settlement is on a 30-minute basis? Flows on interconnectors can sometimes change direction within a 30 minute period. If this happened, there would need to be a process for managing any disparities between the 5-minute dispatch and 30-minute settlement outcomes.

- How would the scheme address the need to balance a generator's dispatch amount, which is based on the actual generation, and the settlement amount, which is based on the generation that is sent out, accounting for transmission losses?

- How should incentives be set at the start, to ensure that there is no potential for oscillatory behaviour, i.e. when generators may bid their generation up in one interval and down in the next in order to find a balance between obtaining higher prices and being dispatched?

- What would happen if more than one constraint is binding at the same time?

- What would happen if an interconnector is involved in the constraint?

Considerations

The major benefit of this scheme would be that it would firm up IRSR units by eliminating the impact of gatekeeper generator behaviour on interconnector flows, and therefore on the IRSRs. For example, if a gatekeeper generator chose not to generate, thereby reducing interconnector flows, that generator would need to "supplement" the IRSR funds to compensate unit holders for forgone residues due to reduced interconnector flows. While the scheme also has positive benefits for dispatch efficiency by improving incentives for the gatekeeper generator, it is difficult to analytically determine the dispatch efficiency in the presence of strategic bidding more broadly.

Additionally, this proposal is for a NEM-wide change and therefore represents a substantial reform. In this Review, we have considered proposals for NEM-wide change in the context of the materiality of the congestion problem to date. The historical level of congestion at this stage has not been material enough to warrant NEM-wide solutions. Section C.5 discusses are reasoning for not pursuing NEM-wide solutions in more detail. We are therefore not recommending the gatekeeper alternative as a proportionate response or alternative to funding negative settlement residues at this time.

C.4.4.4 CS Energy generator funding of negative residues proposal

At the PFC workshop CS Energy presented an option in which generators would fund negative settlement residues arising on an interconnector.

Proposal objective

This proposal would increase the firmness of IRSRs relative to zero flow clamping by having generators elect to fund the negative settlement residues that accrue in absence of NEMMCO clamping interconnector flows.

Proposal description

In this option NEMMCO would calculate and publish information in real time, identifying what proportion of the negative settlement residues each generator would be responsible for, given its current level of generation. This option would not affect NEMDE dispatch. Generators would face the decision to either fund the corresponding negative residues or change their output levels. Generators would be allocated a share of flow through the constraint to their RRN in proportion to available generation and fund negative residues for generation in excess of their share.

Benefits

According to CS Energy, there are a number of benefits from this proposal. It considers that the proposal:

- would not affect NEMDE dispatch and could therefore be implemented relatively easily;
- could be applied locally and preserves the current regional structure; it is therefore not a substantial reform to the NEM;
- need only apply to material constraints, which are determined by the market. The proposal would not require any NEMMCO discretion in the dispatch process; and
- would only include generators who elected to participate.

NEMMCO noted at the workshop that this option was also likely to be simpler to implement than PFC and would not rely on direct market intervention or discretion by NEMMCO.

Issues

In order to implement this alternative there are a number of issues to further consider:

- What are the consequences of the fact that generators would need to re-bid to manage their position?
- How would an event that requires the accumulation of negative residues for system security reasons be addressed? For example, there may be circumstances, such as an islanding event, where it is necessary for the flows to be counter-priced, in order to maintain system security and supply reliability.
- How would the scheme address the need to balance a generator's dispatch amount (which is based on the actual generation) and the settlement amount (which is based on the generation that is sent out) accounting for transmission losses?
- How would the scheme address those constraints that include more than one interconnector?

Considerations

This option has potentially the same main benefit as the Gatekeeper proposal. That is, it will increase the firmness of IRSRs. However, unlike the Gatekeeper proposal, this option is able to be applied selectively and is therefore a localised solution, not a NEM-wide one. Such a change could represent an incremental reform to the NEM. It also enables the market to judge what is a "material" problem and therefore whether or not to apply the scheme.

Given the benefits of this proposal, we support its continued development by its proponents as it focuses on addressing the impacts of clamping, which we identified as a problem. However, we recognise that there are a number of issues that require resolution. Should the proponents develop this option further, then it could be assessed in due course as a Rule change proposal.

C.5 Wholesale market pricing and settlement arrangements

C.5.1.1 Introduction

The manner in which congestion is priced in the wholesale market clearly has an important role to play in managing congestion. This section provides more detailed discussion and reasoning on whether changes should be made to the wholesale pricing and settlement arrangements to improve the management of congestion in NEM. The Terms of Reference for this Review highlighted, in particular, the need to examine mechanisms that could be introduced on a localised (i.e. in respect of a specific constraint) interim basis prior to congestion being addressed on an enduring basis through regional boundary change or through an investment response from transmission, generation or load. We considered the role for such mechanisms in conjunction with identifying and developing improved arrangements for managing financial and physical trading risks associated with material network congestion.

C.5.2 Background

Congestion can cause the marginal cost of electricity (based on bids and offers submitted) to vary across locations. To the extent these variations in the cost of electricity are reflected in prices, participants will face different types of incentives and risks. Price divergences reflecting network congestion can provide important economic market signals and may positively influence behaviour at both the operational (e.g. generator bidding) and investment (e.g. location and timing) levels.

Greater price granularity, which prices congestion explicitly, reduces the level of generator mis-pricing and physical (or dispatch) risk. It reduces the risk of being constrained-off (wanting to generate but not being allowed to) or constrained-on (not wanting to generate but having to). At the same time, it increases the price (or basis) risk that participants need to manage. More prices in the market means participants need to hedge a greater number of possible price differences that arise in the presence of congestion. Any change to the balance between priced and unpriced congestion therefore affects the balance of risks that market participants need to manage. Changes to the wholesale pricing and settlement arrangements therefore need to be considered alongside financial instruments used to manage any increase in the associated basis risk. Such changes are important defining characteristics of options for change.

There is a variety of ways to allow for more locational prices, but they fall into two broad classes of option for change in the NEM. The first is a location-specific, time-limited constraint mechanism which is applied in specific places exhibiting material congestion. The second is a NEM-wide change to the market wholesale pricing and settlement arrangements. This second category includes a range of options. At one end is the existing regional structure where congestion is priced between regions (i.e. across regional boundaries) but not within a region. Under this model, all generators within a region are settled at the RRP. At the other end of the spectrum are more extreme granular pricing options, like generator nodal pricing (GNP), where every generator is priced at its own node and congestion is reflected in each of those nodal prices.

In its *Statement on NEM Transmission* in May 2005, the MCE emphasised the importance of stability and predictability in a regional structure, saying that changes to regions should occur only if they deliver a net improvement to the efficient operation and investment environment of the market. These key principles provide an important framework that promotes region change as a means of addressing transmission congestion only when congestion is enduring and material and when there is a clear economic case for the change. This, in turn, can promote efficient investment options in transmission, generation and load to address congestion in the stages prior to considering a region change.

In December 2008, we made a Rule that implements a new process for region change from 1 July 2008.[257] This Rule introduces an application-based process to region change. The criteria for assessing a proposed region change require the AEMC to be satisfied that the solution will materially improve economic efficiency. This includes, but is not limited to: improvements in productive efficiency; efficiency in relation to the management of risk and the facilitation of forward contracting; and long-term dynamic efficiency.

This new process for region change is more open and transparent than the current process in rule 3.5 of the Rules. It facilitates better informed, more robust and accountable decision-making than under the previous Rule. It will also help ensure that any future new region boundaries will reflect "choke points" of material and enduring congestion, creating clear price incentives for the more efficient location of loads and use of electricity services.

In assessing how changes to the existing wholesale pricing and settlement arrangements could be used to manage congestion, we considered:

- the range of options for more granular wholesale pricing and settlement
- the appropriateness of constrained-on payments for generators; and
- information on mis-pricing that would give participants a way of identifying historical levels and locations of congestion.

We discuss these issues in the following sections.

C.5.3 Options for more granular wholesale pricing and settlement

In the Draft Report, we discussed incremental changes as well as fundamental reforms to the way congestion is priced in the NEM.

The *incremental change* was to amend pricing for constrained-on generation.

The options we classified as *fundamental reforms* to the NEM were:

- limited forms of nodal pricing;

---

[257] *National Electricity Amendment (Process for Region Change) Rule 2007 No 11*. See AEMC 2007, Process for Region Change, Rule Determination, 20 December 2007, Sydney. Available: www.aemc.gov.au.

- CSP/CSC; and
- CBR.

We assessed these options carefully in the light of stakeholders' views, evidence on the incidence and materiality of congestion (see chapter 2 of the Final Report and Appendix B), and subsequent analytical work on the characteristics and practicalities of the different options. Importantly, all of these options, as well as the many variants and hybrids that exist, represent different ways of addressing the same core issues. We therefore developed a common analytical framework and terminology to explicate and to compare the options.

C.5.3.1 Analytical framework

Appendix A introduced the concepts of dispatch and the role of transmission constraints in limiting dispatch to ensure it remains within safe and secure limits. This provides the foundation for understanding the different pricing options available for managing congestion. This section will expand on that foundation by setting out a framework for describing and understanding how network congestion can be reflected in the way the wholesale market is settled.

Constraint prices

A constraint which binds imposes a cost on the market. This cost can be measured directly by calculating the reduction in the total cost of the dispatch (based on the bid prices submitted to the dispatch process) that would result if the binding constraint could be marginally relaxed. This can be interpreted as the "price" of the constraint. When a constraint does not bind, the total dispatch cost will be unaffected by relaxing the constraint limit slightly. Hence, a constraint only has a positive price when it binds.[258] A constraint price is specific to the dispatch interval in which it binds. If the same constraint binds in a different dispatch interval, then the constraint price may well be different.

Constraint prices can be used to calculate the extent to which a particular point on the network is "mis-priced" relative to its RRN.[259] If there are no binding constraints, then there will no mis-pricing.[260] If a constraint binds, then locations on

---

[258] More precisely, the constraint "price" reflects the impact on the total dispatch cost from increasing the limit by a small amount. For a constraint which is formulated in the "less than or equal to" form, an increase in the limit relaxes the constraint, resulting in a reduction in the total dispatch cost, and therefore a positive "price". There are a few constraints formulated in the "greater than or equal to" form. For these constraints, an increase in the limit implies a tightening of the constraint and therefore an increase in the total dispatch cost and a negative "price". For an "equal to" constraint, an increase in the limit cannot, a priori, be determined to be a relaxation or a tightening of the constraint. For these constraints the constraint "price" has an indeterminate sign.

[259] For further discussion of mis-pricing and its potential economic consequences, see Appendix A.

[260] At least if losses are ignored. To be more precise, the NEM uses an approximation to real physical losses within each region in the form of static marginal loss factors. There is at least a theoretical possibility that this approximation will lead to a small amount of mis-pricing compared to full nodal pricing.

the network represented by terms in the binding constraint equation will be mis-priced.

The extent of mis-pricing for any particular connection point on the network, at any particular point in time, will be determined by: (a) the constraint price; and (b) the coefficient of the corresponding term in the constraint equation. Where a connection point (e.g. the output of a particular generator) is involved in more than one binding constraint, the extent of mis-pricing at that connection point can be determined by adding up the mis-pricing from each binding constraint equation it is involved in and deriving the local nodal price. This difference between the marginal cost of supply at the RRN and the local nodal price at some other connection point in that Region, based on bids and offers, measures the extent of mis-pricing at that connection point.

Generators are dispatched on the basis of the marginal cost of supply at each individual node, because this ensures that the total cost of the dispatch is minimised. However, each individual generator is settled at the RRP for the output they are dispatched at. Differences between the price at which a generator is dispatched and the price at which it is settled are the source of the risks of being constrained-on or constrained-off. This, in turn, creates incentives for dis-orderly bidding.

Constraint rents

A constraint which is binding indicates that transmission capability is a scarce resource to the market. The value of this scarce resource is equal to the volume of energy (in MWs) being constrained multiplied by the constraint price. This can be interpreted as a "rent" earned by the constraint when it binds. A rent is generated every time a constraint binds. How these rents are distributed, either implicitly through the dispatch process or explicitly through the sale or allocation of financial instruments, is a key feature that differentiates one constraint pricing mechanisms from another.

Financial instruments derived from congestion rents

Constraint rents are the building blocks of any arrangement that reflects network congestion in prices in the wholesale market. Congestion price risk can be characterised as parties being exposed to (i.e. required to fund) these rents when they occur. Financial instruments can be designed to help manage such price risk. The basic approach is to design a financial instrument to enable parties to buy a share in the congestion rents when they occur (and thereby hedge the risk). The two main approaches to designing such an instrument are to have either:

- an "unbundled right" to a share of congestion rents for each individual constraint equation involved in the congestion pricing scheme; or

- a "bundled right" to a share of congestion rents across a "bundle" of constraint equations (e.g. all the constraint equations involved in the congestion pricing scheme).

A FTR is a form of bundled right, involving the bundle of constraints affecting prices between two nodes. An IRSR unit is another example of a bundled right.

Methods of distributing congestion rents

A set of congestion pricing arrangements would also need processes to determine how financial instruments derived from congestion rents are to be distributed. There are three main approaches:

- "auction" the rights;
- "negotiate" a distribution of rights, and "arbitrate" if no agreement can be reached; or
- "allocate" the rights in accordance with an administrative rule set when the localised pricing intervention is established.

These approaches relate to congestion pricing arrangements in which rights to congestion rents (or "bundles" of congestion rents) are identified explicitly. There is also the option to allocate rights to congestion rents implicitly through other processes, such as a dispatch process. This is a key feature of the NEM arrangements, and is discussed in more detail below.

Using the analytical framework to characterise different approaches

This section applies the analytical framework set out above to describe different approaches to congestion pricing, including the current NEM arrangements and options for reforming them.

Nodal markets

In nodal market designs, there is no difference between the price at which a market participant (e.g. a generator) is dispatched and the price at which it is settled; the settlement price is equal to the marginal cost of supply at each node. There is minimal risk of being constrained-off or constrained-on, but there is additional price risk to manage. If a market participant with an exposure to a given connection point wishes to contract with any other market participant at a different connection point, the (first) market participant will be subject to an additional risk, often known as "basis" risk.

Nodal markets generally have (or seek to develop) financial instruments, such as FTRs, to enable parties to manage this price risk. FTRs are, essentially, a right to a share of the congestion rents resulting from (the bundle of) binding constraints affecting electrical flows between two points on the network – as revealed by a price difference and power flow between the two points. In practice, nodal markets tend to bundle FTRs around the concept of "trading hubs". Market participants are able to buy a portfolio of financial instruments to, in effect, hedge the price risk between trading hubs and from their individual location to their local trading hub.

The NEM market design

The NEM market design formalises the concept of a "trading hub" through the definition of RRNs. In many ways, a RRN serves the same purpose as a trading hub. It represents the locations at which financial contracts tend to be written, and is used in structuring financial instruments (i.e. the IRSRs) for managing the price risk of trading between RRNs. However, RRNs are regulatory, rather than commercial, constructs; consequently a regulatory process has to be followed if they need to be changed. In contrast, changes to trading hubs in a nodal setting evolve through changes in commercial behaviour. In principle, a commercial construct might be expected to be more dynamic and flexible. In practice, trading hubs in some nodal markets have proven to be quite resistant to change.

The main difference between the NEM and a nodal market relates, however, to the nature of price risk within a region (in the NEM) or within the scope of a 'trading hub' (in a nodal market setting). In a nodal market, individual market participants are responsible for managing the price risk between their location and the local trading hub. In the NEM, this risk is managed automatically for participants through the settlement process. In effect, when a generator is dispatched, it automatically receives through the regional settlement regime an implicit financial instrument that perfectly hedges the price risk between its location and the RRN for its dispatched volume of output. The precise value of this "implicit FTR" is always the Pseudo Nodal Price multiplied by the actual output.

When the definitions of the pricing regions change, so does the balance between (a) congestion that is explicitly priced and (b) the corresponding distribution of implicit financial instruments to hedge price risk within regions. This can be illustrated using our Final Rule Determination to abolish the Snowy Region.[261] This change:

- reduces the number of settlement prices (from six to five);

- reduces the number of hedging instruments (by abolishing the IRSRs between Victoria and Snowy and between New South Wales and Snowy, and by creating new IRSRs between New South Wales and Victoria); and

- retains the existing method of distributing IRSR units (through the Settlement Residues Auctions) and distributing intra-regional "implicit FTRs" (matched to the dispatch)—with Murray now receiving an implicit FTR providing settlement at the Victoria RRP, and Tumut now receiving an implicit FTR providing settlement at the New South Wales RRP.

Using the analytical framework to characterise potential changes to the NEM design

Several options for pricing congestion in the NEM (listed at the start of section C.5.3) were discussed in our Directions Paper. These included options that might

[261] AEMC 2007, *Abolition of Snowy Region*, Final Rule Determination, 30 August 2007, Sydney.

potentially be invoked on a localised, time-limited basis in response to specific congestion issues.

All the options involve a degree of localised spot market pricing in an attempt to overcome the mis-pricing problem. The key distinguishing feature between them is the manner in which rights to congestion rentals are "bundled". Here we characterise the different options in terms of this feature.

Bundled rights options

There are a number of variants in the class of congestion pricing options which involve bundled rights to the congestion rents. The most obvious, and well-documented, example is CSP/CSC.

<u>CSP/CSC</u>

The CSP/CSC framework has been developed specifically in the context of the NEM, through work undertaken for the MCE by Charles Rivers Associates. The Terms of Reference for this Review required us to have regard to this work. There are a number of ways of applying the CSP/CSC framework, but the basic model, when applied to give effect to more refined locational pricing for generators, has the following characteristics:

- A set of generators (and interconnectors) and a set of constraints is identified. For example, in the CSP/CSC Trial in the Snowy Region the scope of the pricing intervention was defined in terms of a list of around 130 individual constraint equations representing the flow limit between the Murray and Tumut nodes in the Snowy Region, and encompassed the generators (and interconnectors) involved in those constraint equations (i.e. Upper Tumut, Lower Tumut, Guthega, Murray, Snowy-NSW interconnector, and VIC-Snowy interconnector).[262]

- Each generator involved in the scheme that is exposed to congestion prices is allocated an explicit financial instrument (a CSC) which entitles it to have a specified volume of electricity settled at the relevant RRP (this volume does not change with the identity of the particular constraint that is binding).

- Any generation output over and above the amount specified in the CSC is settled at a price consistent with the congestion prices implied by the constraints involved in the scheme (in effect, an approximation of the exposed generators' local nodal prices).

- The net settlement is therefore a weighted average of the RRP and each exposed generator's nodal price - with the weight of the nodally priced part being determined by the extent to which a generator exceeds its CSC.

---

262 The Snowy CSP/CSC trial was a *partial* implementation of the CSP/CSC concept in that it did not allocate explicit CSCs to one of the interconnector terms involved in the constraints — the VIC-Snowy interconnector. See Appendix E of AEMC 2006, *Management of negative settlement residues in the Snowy region*, Final Rule Determination, 14 September 2006, Sydney.

- In addition, each interconnector in the scheme is entitled to congestion rents equal to the price difference between the two regions multiplied by a pre-specified volume of its flow (i.e. an explicit CSC volume).[263] These congestion rental payments to (or from) each exposed interconnector modify the net value of the IRSR fund, which comprises the bundle of all constraints that cause price differences between regions. The SRA process is then applied to the modified IRSR fund, with the auctioned products providing firmer hedging than under the status quo.

- Any congestion rents not explicitly allocated the generators and interconnectors exposed to the congestion prices in the congestion pricing regime would be allocated implicitly to market participants in accordance with dispatch volumes, as occurs under the status quo regional settlements regime.

This option has been developed with the intention of it being applicable to specific setting in the NEM and could be adopted for a limited of time.

LATIN Group proposal[264]

The Latin Group in its response to this Review's Issues Paper, put forward a fully-developed CSP/CSC proposal. The proposal focussed on, among other things, the difficulties associated with identifying and implementing CSP/CSC on a localised, incremental basis. The solution identified in the proposal was to:

- apply CSC/CSP across the whole NEM;

- make a one-off allocation of CSCs (i.e. financial rights to be settled at the RRP) to all existing generators on the basis of a representative dispatch scenario – with CSCs being "non-firm" (i.e. scaled back to match available physical capability) and lasting for the duration of the associated generation asset;

- make automatic adjustments to the original allocations of CSCs in the event of extra network capacity being made available; and

- allocate CSCs to interconnector flows, as a means of firming up the IRSR units as a hedging instrument between RRNs and removing negative settlement residues.

This option has been advocated as a permanent change to the arrangements, and would apply NEM-wide.

Other bundled options

There are a number of alternative options which increase the amount of congestion pricing and adopt some other mechanism for re-distributing the associated congestion rents.

---

263 The interconnector receives an explicit CSC for a defined MW volume in the constraints included in the congestion pricing scheme in which the interconnector is involved and exposed to congestion prices.

264 LATIN Group, submission to AEMC Congestion Management Issues Paper, April 2006

To illustrate this range, a highly *bundled* variant could be considered. The congestion rent bundles under this option would be constructed to orient a set of generators to an alternative “pricing hub”. The additional hedging instrument sold through auction would be for a share of the congestion rents accruing between the newly formed pricing hub and the RRN. This would have very similar characteristics, from the perspective of generator pricing and management of price risk, to the creation of a new region. However, it would leave the regional pricing of load unaffected. In effect, this option would create an additional “interconnector” (for generators) within an existing region.

“Unbundled rights options”

There is another class of options for congestion pricing schemes which seek to “unbundle” the congestion rights implicit in the existing IRSRs or in the CSP/CSC proposal and instead, allocate rights based on each individual constraint equation. One proposal based on this approach is the “Constraint-Based Residues” approach.

<u>Constraint-Based Residues (CBR)</u>

The CBR model specified in Biggar (2006) is an example of an *unbundled* approach – the economic rent (residue) is identified for each constraint equation and placed into its own separate fund. Rights to shares in these funds would then be either allocated or auctioned. Participants would have an opportunity to trade these rights (or to acquire them at an auction) in such a way as to construct the financial hedges there require, such as to construct a point-to-point FTR or to construct separate hedges for particular outage conditions as compared to system normal conditions, etc.

The most general form of CBR set out in Biggar (2006) is not limited to generators. It extends the principle of congestion pricing to all terms in all constraint equations, including load.

C.5.3.2 Discussion and assessment of options

We assessed the options discussed in the previous section against the Review’s Terms of Reference and the National Electricity Objective. We used these criteria to develop an assessment framework based on the following inter-related factors:

- influence on bidding behaviour and dispatch efficiency;
- practicability and complexity of implementation;
- allocation of congestion rights and competition issues;
- predictability and regulatory risk; and
- proportionality of response.

Influence on bidding behaviour and dispatch efficiency

Addressing mis-pricing

As noted above, all of the pricing options for fundamental reform that were put forward would involve a degree of localised wholesale spot market pricing. This means that the affected generators would be settled at a price that wholly or partly reflected their local nodal price, depending on the number of constraints included in the arrangements and which constraints were binding at a given time. The practicability of implementing such options is considered in the next section. However, a key issue is whether more "correct" wholesale pricing is likely to enhance or detract from the economic efficiency of dispatch.

In a market characterised by price-taking bidding behaviour, ensuring that settlement prices are consistent with the prices used in the dispatch process ought to promote the economic efficiency of dispatch. This is because participants' marginal decisions would be based on their local nodal price rather than the RRP. Generators will not have incentives to bid in a dis-orderly manner (e.g. -$1 000/MWh bids) if dispatch and settlement prices are aligned. Snowy Hydro, Origin Energy and ERAA saw merit in a constraint pricing mechanism, like CSP/CSC, as a transitory solution to congestion.[265]

However, where generators have some degree of market power, it is not possible to conclude on the basis of analytical reasoning alone whether more localised pricing arrangements would enhance economic efficiency. This is because generators with some influence over their local nodal price may seek either to withhold a proportion of their output or to offer it at a very high (non-cost-reflective) price in order to maximise their profits based on a price-volume trade-off. One manifestation of this behaviour might be a tendency for generators to leave some spare capacity or "headroom" on the transmission network between their location and higher-priced nodes. The absence of locational pricing may provide incentives to such generators to bid at or below their resource costs in order to be dispatched. They would not benefit from exercising any transient market power they have.

This issue was highlighted in our analysis on the various Rule change proposals concerning the Snowy region. While one of the options (the Southern Generators' congestion pricing proposal) would have ensured both Murray and Tumut generation received their theoretically correct local nodal prices, we found that this could provide incentives for Snowy Hydro to generate less at peak times than in the Snowy region abolition proposal. In the Southern Generators' congestion pricing proposal, Snowy Hydro had incentives to maximise its volume against the Victorian or NSW RRP for southward or northward flows, respectively.

The presence of a degree of market power means that correcting mis-pricing does not necessarily improve the economic efficiency of dispatch. In such an environment, as was the case in the Snowy region situation, the extent to which outcomes are likely to be efficient is an empirical matter.

---

[265] Snowy Hydro, Draft Report submission, p.1; Origin Energy, Draft Report submission, pp.2-3; ERAA, Draft Report submission, p.2.

Impacts on hedging

The introduction of localised congestion pricing also affects the ability of market participants to hedge price risk effectively. The introduction of more settlement prices for generators has two effects. First, it reduces the extent to which constraints involving both local generators and interconnector flow terms dilute the firmness of the IRSR units when they bind. Second, it reveals the need for additional hedging instruments for managing trading risks within and between regions.

There is a large number of constraints in the NEM which relate to technical limits on the combined behaviour of generators in a region and interconnector flows to that region (which in turn reflect the behaviour of generators in other regions); for example, situations where a limited amount of transmission capability is available across a set of generators, some of which are in a different region. The constraint might bind with low interconnector flow and high regional generator output, or high interconnector flow and low regional generator output.

Under the NEM settlement Rules, when the constraint binds at a low interconnector flow, a congestion rent is implicitly transferred from the relevant IRSR fund to the dispatched generators.[266] This process detracts from the use of IRSRs as a hedging instrument. Localised congestion pricing, in combination with the distribution of explicit rights to the resultant residues, can increase the firmness of the IRSRs.

Combining the introduction of localised congestion pricing with the introduction of additional financial instruments for hedging congestion price risk offers a theoretical means of increasing the volume of firm hedges available in the market. For example, the introduction of CSCs was seen as an essential complement to the introduction of CSPs because it allows congestion risk to be actively managed via the allocation of CSCs. A generator which is allocated a CSC for a volume of output has more certainty over its ability to sell that amount of energy at the RRP than it does under the current arrangements in the absence of a CSC. This increased sophistication in the range and detail of financial instruments for hedging risk (in this case, the uncertainty over the volume of electricity settled at the prevailing RRP) can enhance market participants' ability to manage risk. This in turn can support higher volumes of contracting within and across regions.

However, "nodalising" the price for congested power stations has a dual impact for a business. Firstly, combining the possible lost quantity and lower unit price introduces a new form of intra-regional basis risk. Secondly, while the mechanism may improve dispatch in the physical market, it may be perceived as a retrograde step in the hedging market.[267]

Effect on longer term decisions

---

266 The converse can apply also, where a constraint is formulated such that a generator can enable more flow on an interconnector by increasing its output. This is the so-called "gate-keeper" generator. There is an implicit transfer of rent from the gate-keeper to the IRSR fund if the gate-keeper increases its output. If the gate-keeper does not have a financial incentive to increase its output (e.g. because it is being settled at the RRP), then the firmness of the IRSR (and the volume of inter-regional hedging available) can be reduced.

267 Babcock and Brown Power, Draft Report submission, p.2.

As discussed earlier, there are a range of locational signals present in the NEM under the current design and Rules. VENCorp noted a congestion pricing signal, like that provided by a constraint pricing mechanism may influence investment location decisions, where other factors are marginal.[268] However, we are not persuaded that a location-specific interim constraint management mechanism will strengthen or clarify these signals. This is because a location-specific interim constraint management mechanism is uncertain and temporary in application. Hence, the pricing outcomes that might result from its implementation are also uncertain. Prospective investors will not generally know whether (or how) a particular project will be affected by such a constraint management mechanism or not when they make decisions to invest (or dis-invest). It could also be argued that the uncertainty over whether a project will be priced regionally or locally (for an unspecified period of time) reduces the clarity of existing locational signals, by creating more regulatory "noise". Under either scenario, the possibility of a location-specific interim constraint management mechanism does not improve locational signals for investment.

In addition, a location-specific interim constraint management mechanism may also affect the ability for participants to access financing to invest. A location-specific interim constraint management mechanism, and the increased risk and uncertainty such a mechanism introduces to the market, will add to the uncertainty of power project financing. This may increase the cost of capital and therefore the costs for a new entrant.[269]

In general, we were persuaded that a location-specific interim mechanism would materially and positively influence the efficiency of investment decisions.

Practicability and complexity of implementation

This Review's Terms of Reference specifies that we must develop a constraint management mechanism for managing material congestion prior to its being addressed by investment or regional boundary change. Practicability and complexity of implementation are important considerations in determining what types of mechanism would be appropriate, when considering such mechanisms under our statutory duty to promote the National Electricity Objective.

A key implementation issue for a location-specific interim constraint management mechanism is the means of allocating rights to congestion rents (which afford protection from intra-regional price risk). This is discussed in detail in the following section. This section is restricted to other implementation questions around a location-specific interim constraint management.

The Draft Report highlighted some of the difficulties with the implementation of a location-specific interim constraint management mechanism, including:

- the threshold criteria and process for *introducing* a constraint pricing mechanism;

268 VENCorp, Draft Report submission, p.2.

269 Babcock and Brown Power, Draft Report submission, p.5.

- the identity of the constraints to be "priced" as part of the regime; and
- the threshold criteria and process for *removing* a constraint pricing mechanism, given that it is intended to be an interim measure only.

While the trial of a CSP/CSC instrument at Tumut (the Snowy Trial[270]) tackled some of these issues, we do not believe that the implementation approach adopted for the Trial is easily applied to other settings.

While the Snowy Trial was a positive development for the market, in two specific ways, it represented a special case, possibly unique in the NEM.

- The underlying congestion problem was clearly identifiable, well understood, and unlikely to change in the short to medium term.
- Only one generation company (Snowy Hydro) and two plants it owned (Lower Tumut and Upper Tumut) were involved in the trial. This made it relatively straightforward for market participants to agree on an allocation of CSCs between the Snowy-NSW interconnector and Snowy Hydro's Upper and Lower Tumut generation plants because the level of interconnector flow with and without the output of these generators is simple to establish.[271]

The analysis undertaken for this Review on the incidence and materiality of congestion demonstrated that, apart from the Snowy region, congestion in system normal conditions have generally been relatively unpredictable and transitory. This accords with the views of a significant number of stakeholders provided at the Industry Leaders Forum on congestion[272], and more generally through engagement with stakeholders.[273] However, other stakeholders such as "the Group"[274] and the NGF contended that congestion is sufficiently material to warrant consideration of congestion pricing reforms.[275]

In its Draft Report submission, the Group stated that we did not assess either the costs or trading risks of implementing a location-specific interim constraint management mechanism and therefore could not determine a materiality threshold

---

270 In the Snowy Trial, the intent was to enable Snowy Hydro's Tumut generation to be settled at its local nodal price for its marginal output when the Murray/Tumut constraint was binding. When flows through Snowy were in a northward direction, this would increase Tumut's incentive to generate at times of high NSW prices. When flows through Snowy were in a southward direction, this would reduce Tumut's incentive to generate and consequently reduce the likelihood of counter-price flows.

271 Conversely, the non-allocation of explicit CSCs to the VIC-Snowy interconnector in the partial implementation of the CSC/CSP concept meant that there was considerable controversy about the way in which implicit CSCs were allocated to the VIC-Snowy interconnector when NEMMCO intervened in the dispatch process to limit the accumulation of negative residues.

272 AEMC, Industry Leaders Forum – Summary of discussion. Available at www.aemc.gov.au.

273 Macquarie Generation, Draft Report submission, p.1; CS Energy, Draft Report submission, p.1.

274 The Group comprises of: LYMMCO, AGL Energy, International Power, Flinders Power, InterGen Australia, and Hydro Tasmania.

275 The Group, Draft Report submission, p.2; NGF Draft Report submission, p.2.

or net economic benefit to determine whether or not the NEM should have such a mechanism.[276] Hydro Tasmania agreed.[277]

This raises a critical practical issue for application of forms of localised pricing intervention. How is the need for the intervention identified sufficiently far in advance to allow managed and orderly design and implementation, if potential leading indicators (e.g. historic incidence of congestion) are not reliable?[278] While locations can be identified easily with the benefit of hindsight, it is not clear that they can be forecast accurately. This is a significant consideration given the importance of forward contracting in the NEM market design. To illustrate, there is anecdotal evidence from a range of stakeholders that the recent congestion issues involving the South Morang constraint in Victoria were not anticipated.

This suggests it is difficult to implement effectively a location-specific interim constraint management mechanism. There are a number of reasons for this. The first is difficult to design and effectively implement a mechanism that will work in all situations. While such a mechanism was introduced in the Snowy region, the unique characteristics of that situation make it highly unlikely that those conditions would arise anywhere else in the NEM.

Second, there is the question of what is an appropriate lead time for implementing such a mechanism. The evidence on prevalence indicated that congestion was relatively transient. This would mean in order for a mechanism to be of value, it would need to be implemented relatively quickly. However, given the volatile nature of the NEM's wholesale market, forward contracting is incredibly important. This would mean introducing a location-specific interim constraint management mechanism at short notice into an environment where most participants were already heavily contracted.

The MCE stated the importance of forward notice when it proposed a new process for region change. It recommended a minimum implementation lead time of three years.[279] The purpose of the proposed three-year lead time is to provide market participants with adequate time to adjust to the region change. The contracting implications of a location-specific interim constraint management mechanism are similar in nature to those associated with changing region boundaries. There is therefore a question as to why an interim mechanism should have a shorter notice period compared to a region change given market participants would need to amend their contracting positions to respond to its introduction.

If congestion pricing interventions were adopted in other circumstances, the evidence on the apparently transitory nature of congestion – and the lack of robust leading indicators - suggests two possible risks. First, that instances where a location-specific interim constraint management mechanism might improve the

---

[276] The Group, Draft Report submission, pp.2-3.

[277] Hydro Tasmania, Draft Report submission, p.4.

[278] EUAA, Draft Report submission, p.15.

[279] AEMC 2007, *Process for Region Change*, Final Rule Determination, 20 December 2007, Sydney.

efficiency of outcomes are missed. Second, that location-specific interim constraint management mechanisms are introduced where they deliver no benefit.

Allocation of congestion rights and competition issues

The question of how to allocate explicit congestion rights cannot easily be resolved. Some submissions to the Draft Report agreed that the allocation of transmission rights would be controversial and could create wealth transfers without efficiency improvements.[280]

The LATIN Group proposed one possible allocation method. It suggested that CSCs could be allocated to all existing generators on the basis of a representative dispatch scenario. This would have the advantage of ensuring that the timing and location of new investment in generation was based on future expected spot prices at the relevant location, rather than the proponent's expectation of being able to obtain financial settlement at the RRP by bidding in a dis-orderly manner.

In its Draft Report submission, Origin Energy proposed an allocation based on constrained capacity (or financial access to the constrained region's RRN) on the basis of the individual generator's capacity share in the overall generation capacity contesting a particular constraint. A share may also need to be allocated to an interconnector to ensure competitive neutrality. The fixed, but not firm, access would be allocated to existing generators only. New entrants would not change the allocation, and would only receive fixed access rights for any additional transmission capacity they fund.[281]

However, there are possibly detrimental impacts from allocating explicit congestion rights to incumbents in these ways.

The allocation of explicit rights based on historical dispatch would create its own implementation challenges. Put simply, what historical dispatch should be used? There are dispatch outcomes every five minutes all of which, it could be argued, are representative to a degree. Why would a generator accept one dispatch over another if the choice is arbitrary (within a range) and if it is disadvantaged by the choice? There would be no simple way to get agreement and reconcile differences. This would be a big challenge as there would be the potential risk of lengthy disputes.

In addition, an allocation method that provided existing generators with (potentially tradable) explicit rights in preference to prospective new entrants could be potentially viewed as discriminatory and anti-competitive. While this consideration was not relevant in the case of the Snowy Trial, it is a more pressing concern in most other settings in the NEM, where there are a number of competing generators potentially affected by the congestion that might be priced through a CSP-type

[280] CS Energy, Draft Report submission, p.1; Macquarie Generation, Draft Report submission, p.1; EUAA, Draft Report submission, p.14.

[281] Origin Energy, Draft Report submission, pp.2-3.

arrangement. Hydro Tasmania commented that rights were already allocated according to dispatch volumes and therefore we were overstating the problem.[282]

However, a change in the "allocation" through implementing a location-specific interim constraint management mechanism such as CSPs/CSCs can involve significant wealth transfers and represent material changes to the way in which the market operates over time. Consistent with good regulatory practice, such intervention should not be considered lightly and should only be used if they are effective and proportionate to the problem being addressed.

Alternatively, congestion rights may be allocated through an auction process. In theory, selling rights would ensure those participants who value the rights most would receive them, which would appear to be more consistent with non-discrimination and economic efficiency. However, to implement such a framework of periodic auction, for potentially a very large number of constraints, which would add greatly to the complexity of the NEM trading environment. This would represent a very large change to address an issue of apparently limited materiality based on historic evidence.

In addition, the nature of congestion rights is likely to change over time as constraint equations are altered to reflect transmission augmentation, changes to the provision of NSCS, new generation investment and load growth. Purchasers of explicit congestion rights would be faced with uncertainty over the value of their explicit rights in these circumstances. We recognise that participants currently have to deal with uncertainty over constraint equations and dispatch. However, currently participants have a degree of familiarity with the current arrangements and the Final Report recommendations on improving the transparency and information around constraint formulation and invocation should assist in this regard. The question is whether the selling of rights will make these changes less predictable.

Predictability and regulatory risk

The previous sections have already touched on the different forms of uncertainty that would accompany the implementation of localised and time-limited congestion rights. Each step of the implementation and rights allocation process would be contentious and time-consuming. Changes to the topography of the network or new investments in generation and load infrastructure—possibly even the changes brought about by improved service incentives on TNSPs—could have major effects on the specification and value of transmission congestion rights.

Further, even if implementation of a location-specific interim constraint management mechanism were uncontentious amongst participants, the risk would remain that a mechanism could be implemented in circumstances where there proves to be no material congestion problem to address. In other words, it is possible that the implementation of a regime would be subject to "regulatory failure". While it could be contended that this risk is relatively small because the additional price risk will be minimal if there is no congestion, an alternative view is that the possibility of

282 Hydro Tasmania, Draft Report submission, pp.5-6.

inappropriate or poorly focused regulatory interventions in the pricing and settlement arrangements creates an additional form of regulatory risk. In addition, if there are several interim mechanisms in place, this could hinder the consideration and implementation of more effective policy responses. It may be more effective and efficient to consider a broader response to the localised congestion rather than continuing to address it on a location-specific interim basis.

Proportionality of response

The endorsement of a pricing approach to improve congestion management would, in our view, be a disproportionate response to the problem under examination, given:

- the evidence of limited material congestion in the NEM persisting beyond one or two years at any given location;
- the difficulty of predicting when and for how long congestion will occur;
- the temporary nature of any congestion management regime and the numerous implementation and allocation problems surrounding the provision of congestion rights for parties to hedge the resulting basis risk;
- the scope for investment or regional boundary change to address material and enduring congestion; and
- the ambiguity over whether locational pricing will actually improve the economic efficiency of dispatch in a market where parties have some degree of market power.

C.5.3.3 Final recommendations and observations

We do not recommend any change to the current wholesale pricing and settlement arrangements as a means of managing congestion over and above fixing the Snowy region and implementing the new Region Boundary change process. In particular, we have carefully considered the possible role of a location-specific interim constraint management mechanism and do not consider its implementation as a permanent fixture of this regulatory framework to be consistent with meeting the National Electricity Objective.

Introducing these sorts of changes to the wholesale pricing and settlement arrangements is undesirable because they would likely raise significant implementation issues and competition concerns, with significant wealth transfer implications. They constitute a disproportionate response to the problems creates by the present levels and impacts of congestion, based on the currently available evidence. Also, given the present levels of congestion are unpredictable and transitory, it is not possible to design a "one-size fits all" mechanism that can be triggered automatically. Such a mechanism, if deemed appropriate, would need to be designed and tailored for each individual circumstance. In addition, the extent of some of the possible NEM-wide changes may also go beyond the scope of the options identified in the Review's Terms of Reference.

While there is not currently a place for a location-specific interim constraint management mechanism or more granular pricing more generally in the NEM, the discussion in chapter 4 of the Review's Final Report raises the question of whether such options (and other wider-ranging reforms to the factors that generator locational signals) may be beneficial in the future. That chapter discusses what impact the climate change reform agenda may have on the NEM, and therefore whether there is a role for more granular pricing options in an environment, should the pattern and materiality of congestion look different then compared to now.

C.5.4 Assessment of pricing for constrained-on generation

We considered whether recommending a change to the pricing of constrained-on generators would be a beneficial incremental change to the NEM pricing and settlement arrangements.

C.5.4.1 Background

A generator is constrained-on if it is dispatched at a level of output above that which it is willing to supply at the prevailing RRP. This can occur because the dispatch process implemented by NEMDE aims to minimise the aggregate costs of serving load based on the marginal cost of supply at each node, while RRPs are calculated as the marginal cost of supply at the RRN. In the presence of congestion, the RRP and marginal cost of supply at different nodes may diverge. For example, a generator might be dispatched for a volume it is offering to supply at a price of $40, despite the RRP being only $30. In this example, the difference between Q_{30} and Q_{40} is the "constrained-on volume". This situation could arise if the generator's output helped relieve a constraint and thereby allowed cheaper generation from elsewhere to supply load at the RRN. Constrained-on generation is therefore a symptom of mis-pricing, which in turn is a feature of a regionally priced market design.

C.5.4.2 Discussion

The question raised in the Directions Paper was whether generators that are constrained-on ought to receive some form of compensation to reflect the difference between the price at which they would be willing to supply and the RRP they receive through the settlements process. Submissions expressed a range of views. Some supported constrained-on payments, questioning whether the absence of such payments was consistent, in principle, with an open, competitive market. Others expressed concerns about how such arrangements would be funded, and whether it was appropriate for constrained-on payments to be considered in isolation from other means of managing congestion.

Our recommendation in the Draft Report was *not* to implement a regime for constrained-on payments.

The current Rules

The Rules currently provide a framework for constrained-on generation. The framework incorporates the following elements:

- additional payments from NEMMCO for constrained-on generators are not permitted;

- if a generator is constrained-on through a formal direction from NEMMCO, compensation is payable with minimum compensation based on a cost-based formula; and

- constrained-on payments can also be accommodated in agreements between generators and Network Service Providers, in the context of negotiated access charges under Chapter 5 of the Rules.

Given the existence of this framework in the Rules, we are not persuaded by arguments that there is something fundamentally "unfair" about constrained-on payment not being more widely applicable in the spot market pricing and settlement arrangements. The case for changing the regime for constrained-on payments must therefore be assessed on the basis of its economic impacts in the context of the National Electricity Objective.

Different options for constrained-on payments

Congestion pricing based

Constrained-on payments could be considered as a form of congestion pricing. If a constrained-on generator were "exposed" to the price of congestion between its location and the RRN, it would be settled at a higher price than the RRP. The *right* to be settled at the RRP for a constrained-on generator is, in effect, a *liability*. This contrasts with a constrained-off generator, who would be settled at a lower price than the RRP if it were exposed to congestion pricing. This illustrates that settlement of the basis of RRPs involves a transfer of economic rents between market participants, such as from constrained-on generators to constrained-off generators.

One option for implementing constrained-on payments is through a congestion pricing scheme of a type discussed in the previous section, such as a CSP/CSC. In practice, it would be a modified, asymmetric form of CSPs/CSCs, which would apply NEM-wide. Generators would only have the *right* to be settled at the RRP for the volume of output they were willing to sell at the RRP. Any output over and above this level would be settled at the CSP, being the local price with the price of all congestion costs relating to the selected constraints included. This would be similar to a pay-as-bid settlement approach for the volume of output being constrained-on.

There are two main issues with this type of arrangement. First, it creates short-term, but potentially very acute, pockets of temporal market power that would have to be dealt with. If a generator knew with certainty (as might be the case under certain outage conditions) that it would be constrained-on, it could set its own price for the amount of constrained-on output.[283] The NGF posed, however, that when generators receive a level of compensation based on their bid or spot price, "concerns about the potential for the misuse of market power should not be given preference over increased efficiency in dispatch or improved locational signals for investment".[284]

The potential abuse of localised market power can be dealt with effectively using contractual or regulatory means — such as minimising (or eliminating) the exposure of a participant with market power to its local price via the allocation of congestion rental rights, and/or by other contractual arrangements. Such approaches are often used in other electricity markets, where localised market power is an issue, and have been used in the NEM in restricting the allocation of IRSR units to Snowy Hydro. They do, however, add a new layer of regulatory intervention to the market design. Localised abuse of market power that is transparent and exercised over a relatively small customer base should be of much less concern that the less transparent abuse of market power over a large customer base. In contrast, the abuse of market power in large regions affects a greater number of customers, but is often masked and is therefore more difficult to detect and mitigate.[285],[286]

Second, this type of arrangement would require an external source of funding because it is a one-sided arrangement in which there are not reductions in settlement payments to constrained-off generators. Symmetric forms of congestion pricing, such as CSCs or CBR, are, by definition, revenue neutral – they redistribute existing rents If the scheme were not to be funded internally, through redistribution, then an external source of funding would be required, e.g. from higher charges to load customers.

Compensation based

An alternative method of implementing a form of constrained-on payments is through compensation payments from NEMMCO. This would, in effect, extend the scope of the approach adopted when a generator is constrained-on through NEMMCO direction to encompass all instances where generation is constrained-on. Many submissions to the Draft Report supported this approach.[287]

The NGF proposed a compensation scheme that involved generators electing one of two alternative compensation approaches: a short-run (or bid) price or a long-run (LRMC) price. If a generator selects the short-run approach, it would receive its bid price for each MWh sent out during a trading interval to relieve congestion. Under the long-run approach, every three to five years a generator would elect the method

283 The potential abuse of market power in this way could be mitigated by contracting arrangements.

284 NGF, Draft Report submission, p.4.

285 AEMC 2007, Directions Paper, Congestion Management Review, 12 March 2007, Sydney, p.14.

286 Harvey, S.M. and Hogan, W.W. 2000, "Nodal and Zonal Congestion Management and the Exercise of Market Power", Harvard Electricity Policy Group, Cambridge, Mass., 10 January 2000. http://ksghome.harvard.edu/~whogan/zonal_jan10.pdf.

287 Macquarie Generation, Draft Report submission, p.2; Hydro Tasmania, Draft Report submission, p.2; ERAA, Draft Report submission, p.5.

for compensation. Under this second approach, a change would only be permitted under exception circumstances.[288]

Currently, the costs of NEMMCO compensation payments linked to directions are recovered through market fees. Extending the scope of these payments would increase market fees. An alternative approach would, for example, charge loads, e.g. by recycling costs via TUOS charges. These are both, in essence, forms of “uplift charge”

A compensation-based approach would address one potential concern relating to the exercise of temporal market power by generators, because it would limit the price paid to constrained-on generators through the administered rule for calculating compensation.

Economic impacts of constrained-on generation

We analysed the economic impacts of constrained-on generation in forming a view on whether change to the current framework in the Rules should be changed. We examined the nature of the problems that might be addressed through the introduction of constrained-on payments, the materiality of those problems and the potential for unintended consequences.

Some stakeholders stated that the current mechanism for pricing and compensation through NEMMCO direction and negotiated compensation with TNSPs is inefficient because it is not commensurate to the risks of generation and costs cannot be sufficiently funded.[289] Similarly, some considered that subjecting generators to a NEMMCO direction is a second-best solution and an alternative pricing algorithm would be a better solution.[290]

The introduction of constrained-on payments would address one type of mis-pricing that can occur in the NEM. To this extent, it could reduce the incentives that might otherwise apply for constrained-on generators to manage dispatch risk by bidding in a dis-orderly manner or by understating the physical flexibility of plant for the purposes of dispatch.[291] In doing so, constrained-on payments could overcome one source of dispatch inefficiency and these generators would have one less risk to manage in making investment and operational decisions.

However, the expense of making constrained-on payments to generators would need to be funded by some external party. If the funding for a constrained-on payment scheme were met through a market levy (e.g. in a similar way to the recovery of NEMMCO costs), the expense would be incurred by the generality of market participants, in the absence of clearer method for allocating costs. If the cost were

288 NGF, Draft Report submission, pp.4-5.

289 Snowy Hydro, Draft Report submission, p.2.

290 Hydro Tasmania, Draft Report submission, p.2.

291 Macquarie Generation, Draft Report submission, p.2.

recovered through transmission charges, as proposed by the ERAA[292], then in effect the costs would be recovered from load in the relevant transmission areas in which the constrained-on generator was located.

There could be, however, unintended consequences from the introduction of a constrained-on payments scheme. These relate the scope for, and exercise of, transitory market power by constrained-on generators, including as part of a generator's portfolio. This could impact on the cost of funding the scheme over time. Further, in practice, the incidence of constrained-on generation is closely linked to the incidence of constrained-off generation. This is most evident where there is congestion on a transmission loop. In these circumstances, it might potentially be profit-maximising for a portfolio of generation to enter a combination of bids to contrive a situation of being constrained-on for one of its plant – in order to reap the price benefits of being constrained-off for some of its other plant. A regime of constrained-on payments in this context could simply increase the profits from bidding in a non-cost-reflective manner.

A final economic impact of a constrained-on payments regime is the interaction between transmission and generation. One interpretation of constrained-on generation is that it provides support to the transmission network. The reason such generators are being required to run could be interpreted as reflecting a shortage of network capability. The Rules recognise this interaction and provide for contractual relationships between generators and TNSPs to be made under the provisions in Chapter 5 of the Rules. These could take the form of network support agreements. Imposing a constrained-on payments regime through the pricing and settlement arrangements might be viewed as pre-empting a transmission response. However, it might also be argued that a formalised constrained-on payment regime would give greater visibility to the absence of transmission responses, such as through contract or through investment, and might represent an additional discipline on TNSPs under a service incentive framework.

Materiality of constraining-on

Our general approach to this Review has been to assess potential changes to the existing arrangements in the light of the evidence on the materiality of the problem being addressed by potential change.

The evidence on materiality of congestion is summarised in chapter 2 of the Final Report and in Appendix B. The key observations in respect of constrained-on generation are as follows:

- for the three years from 2002/03 to 2005/06, there were on average around 40 connection points in the NEM that were constrained-on. This is about half the number of connection points that had been constrained-off;
- constrained-off generation was generally affected for a greater number of hours than constrained-on generation; and

292 ERAA, Draft Report submission, p.5.

- there was no constrained-on generation in Victoria, and constrained-on generation was limited to Eraring and Vales Point in NSW.

This evidence does not provide strong support for change. Some submissions to the Draft Report agreed there is minimal need for implementing constrained-on payments regime. CS Energy put forward that network service agreements negotiated with TNSPs provided a workable solution to issue.[293] The EUAA stated that generators already priced the risk of being constrained-on in their bids and offers and a constrained-on payment scheme would mean generators would be paid double for that risk.[294]

In addition, while stakeholders debated the risks of being constrained-on, no submission elaborated on how significant an issue it was. Therefore, we do not find a strong support for change to the current arrangements. This view is supported further by the lack of evidence to demonstrate that existing mechanisms for contractual arrangements between generators and TNSPs are not working effectively. Conversely, we are aware of some examples where contractual arrangements are being used in the context of network support. It is more appropriate, in our view, to let these existing channels work, rather than impose new arrangements that might "crowd out" existing arrangements.

C.5.4.3 Final recommendations and observations

We do not recommend implementing a regime of constrained-on payments through changes to the Rules on settlement of the spot market because it would not represent a proportionate means of improving the management of physical and financial trading risk from network congestion.

While constrained-on payments would address on type of mis-pricing in the NEM, they raise several concerns. First they may create the scope for the exercise of transitory market power by constrained-on generators, especially where a generator owns a portfolio of plant around a transmission loop. Another issue is that imposing a constrained-on payment regime through the pricing and settlement arrangements may be viewed as pre-empting a transmission response under Chapter 5 of the Rules. There is also the outstanding issue of external funding.

In addition, historically, the materiality evidence does not support a case for change. The evidence also suggests that the existing transmission responses are working effectively. We have not found a case supporting implementation of a constrained-on payment regime at this time.

293 CS Energy, Draft Report submission, p.1.

294 EUAA, Draft Report submission, p.18.

C.5.5 Information on the incidence and patterns of mis-pricing

C.5.5.1 Background

As discussed above, mis-pricing arises in regionally priced and settled markets like the NEM in the presence of congestion. Information on the historical incidence of mis-pricing can help market participants understand and manage the risk implications of network congestion.

C.5.5.2 Discussion

While we do not consider there is a case for changing the NEM's wholesale pricing and settlement arrangements to manage congestion, there may be a case for change in the future. The establishment of an information source that identifies the level and location of historical mis-pricing will assist in the future assessment of the materiality of congestion.

Mis-pricing information will also be of value in identifying specific points of congestion, where targeted measures, like network support agreements, could be implemented to assist in the management of congestion. Mis-pricing information will assist participants in identifying areas where they themselves can negotiate such agreements.

Investors will also find value in mis-pricing information as a tool in their decision-making processes. While investment locational decisions are based on a range of factors including access to fuel and water and environmental considerations, access to transmission is also important. Information on mis-pricing will help inform investment location decisions, identifying possible congested areas and therefore prompting a comprehensive assessment of congestion at a preferred location.

The NTP will also make use of the mis-pricing information. In our Draft Report on the NTP, we recommended that the NTP should incorporate any recommendations made in relation to the collection and reporting of congestion related information in this Review. Further, the NTNDP should not be precluded from presenting other similar types of information such as that related to generator mis-pricing, which may be of value to participants in assessing current and future network capability. The historical mis-pricing information provided in the CIR will form a useful source for the NTP in preparing its annual NTNDP.

C.5.5.3 Final recommendations

We recommend amending the Rules to require NEMMCO to publish analysis on the extent and pattern of "mis-pricing" caused by congestion, and to update this analysis regularly. This information will form part of the recommended CIR.

Section C.6.4 presents a more detailed discussion on this recommendation, including stakeholder comments on the recommendation and its implementation.

C.6 Information

The ability of market participants to manage the physical and financial risks arising from network congestion depends in large part on the quantity, quality and timeliness of the information made available to them. Investors also need to be well informed in order to make efficient locational investment decisions for building new transmission and generation capacity—decisions which should contribute to reducing the prevalence of congestion in the longer term. As part of this Review, therefore, we have proposed several ways to improve the information resources available to market participants (and policy makers) on dispatch, risk management, and investment planning.

C.6.1 Background

The information currently published by NEMMCO and TNSPs to help market participants understand and manage congestion is as follows (references in square brackets are to clauses in the Rules):

Daily

- Market Management Systems/Market Data (published by NEMMCO): providing detailed information on constraints used in dispatch, as well as current and historical demand and market prices.
- Pre-dispatch schedule (published by NEMMCO): setting out forecast load, plant availability, peak demand and spot price for each trading interval (clause 3.8.20 of the Rules).
- Daily information (published by NEMMCO): setting out the previous day's market outcomes.
- Short Term Projected Assessment of System Adequacy (ST PASA) (published by NEMMCO): a seven-day forecast of system demand and supply conditions, including forecast plant and network outages and interconnector capability (clause 3.7.3).

Weekly

- Weekly Bulletin (published by NEMMCO): a summary of market outcomes from the previous week.
- Medium Term PASA (published by NEMMCO): a forecast of system conditions for a period of 24 months from the coming Sunday (clause 3.7.2).

Monthly, quarterly or *ad hoc*

- Planned Network Outage (PNO) information (published by TNSPs and NEMMCO): information published every month on the timing and nature of planned outages for the next 13 months and their projected impact on network transfer capabilities; also includes information on the likelihood that outage timing will vary (rule 3.7A).

- Network Outage Schedule (NOS) (published by NEMMCO): published every 4 hours, covering a shorter period than the PNO information.

- Large transmission network consultations (published ad hoc by TNSPs): details of proposed larger (>$10m) augmentations for stakeholder consultation (clause 5.6.6).

- Interconnector Quarterly Performance (published quarterly by NEMMCO): details of historical differences between interconnector capacity and transfer capabilities for each day in the previous quarter (clause 3.13.3(p)).

Annually

- Statement of Opportunities (SOO) (published by NEMMCO)—ten-year outlook of the demand/supply balance by region and NEM-wide (clauses 3.13.3(q-t)).

- Annual National Transmission Statement (ANTS, contained within the SOO) (published by NEMMCO)—setting out forecast utilisation of, and constraints on, national transmission flowpaths and the options that could relieve those constraints (clause 5.6.5).

- Annual Planning Reports (APRs) (published by TNSPs)—details on emerging congestion over the next 10-15 years and options for addressing it (clause 5.6.2A).

C.6.2 Discussion

Our proposal, in the Directions Paper, to improve the provision of information to market participants, received the support of all submissions. There were, however, some qualifications. The transmission owners, ETNOF, suggested that when considering what information TNSPs might provide, we should take into account that: (a) the provision of information is not without cost; (b) information must be meaningful and practical to provide; and (c) information should only be required through the Rules if normal market activities will not delivery it and/or cannot be provided on an user-pays basis. The Southern Generators pointed out that more information would have limited effectiveness because it would not in itself address the problems arising from congestion.

As the Review progressed, we identified two specific areas of information where change is warranted:

- real-time information on planned network events affecting dispatch; and

- information on the incidence and patterns of mis-pricing.

Each of these is discussed in turn.

C.6.3 Real-time information on planned network events affecting dispatch

Market participants need to take measures to manage the impact of constraints, and when they cannot accurately predict the timing of constraints, they find themselves exposed to both physical and financial risk.

Currently, NEMMCO and TNSPs advise participants about network outages through several publications. These are the PNO information, the NOS, and Market Notices. The NOS is currently published by NEMMCO voluntarily. The NOS and PNO information provide market participants with information that is very important to their commercial and operational decisions.

Given the importance of outage information on market outcomes, we believe the Rules should require NEMMCO to publish the information in the NOS and continue to require NEMMCO to publish the PNO information. This information will enable participants to understand, predict, and appropriately respond to those events.

The NOS and the PNO information report on network outages only. There are other types of "events" that affect network constraints. Other factors affecting which constraints NEMMCO invokes include the completion of a network augmentation, the commissioning of a new generator, the decommissioning of an old plant, or the connection of a new industrial load. These factors change the way electricity flows across the network and therefore require new constraint equations to represent the new network configuration. Events such as these can affect which constraint equations are used by NEMMCO, and therefore a market participants ability to understand and manage those trading risks associated with network congestion

For market participants however, there is an information gap for some of these events which affect constraints. For example a TNSP may decide to augment a particular part of the network and will notify the market of this through its APR. For some augmentations, the next time the market hears about the progress of this network change is through a Market Notice from NEMMCO notifying participants about a new constraint equation reflecting this network investment. This gap in information can span several months. Throughout this period, participants face uncertainty over the process between the decision to invest in the network and the inclusion of the new constraint equation reflecting the augmented network into the constraint library, where NEMMCO can use it in market dispatch.

We believe that greater clarity and predictability regarding the impact of a TNSP's actions on likely transfer capability, and on the ultimate expression of this in constraint equations, will be of considerable benefit to participants. We therefore recommended in the Draft Report that NEMMCO should be required to publish information about events (including but not limited to network outages) that may result in different constraint equations being formulated and/or invoked. These events include: network outages; the connection and disconnection of generating units or load; the commissioning (and decommissioning) of new network assets and new or modified NCAS; and network support agreements. Collectively, these events will be defined in the Rules as "planned network events". Information on planned network events will help provide a richer and more continuous flow of information to participants about how these events may affect network capability.

We also recommended that NEMMCO publish information to improve the ability of participants to track and predict changes to the timing of outages and to understand the reasons for changes to outage start and end dates. The NOS does not currently provide all this information. Such information may also place greater discipline on TNSPs and/or NEMMCO to schedule accurately outages, as far as practicable.

NEMMCO currently does not issue market notices to inform market participants when constraints affecting network transfers purely within a region are changed (i.e. when a distribution asset is returned to service following an outage). Market participants have indicated that in order to ascertain when they will be affected by such transfer limits, they rely on informal relationships with network business. The above recommended information outages will help address this problem.

The majority of submissions to the Draft Report supported the recommendation that NEMMCO publish information about congestion-related network events.[295] For example, EUAA noted that this should: (a) enable generators to better anticipate the impacts of constraints; (b) enable retailers to better manage price risk; and (c) reduce information asymmetry.[296]

There were some reservations and qualifications, however.

NEMMCO sought further clarification on the objective of the information resource. In particular, it wanted clearer guidance on what information would assist participants in understanding and predicting the nature and timing of events likely materially affect constraints. It also pointed to the MMS as a useful resource for constraint information and suggested ways to improve it as resource for participants.[297]

Hydro Tasmania supported better information provision to the market so long as the costs of providing it did not exceed benefit to the market. It recommended the establishment of a consultative working group to clarify what information is available and to determine the most constructive and accessible presentation forms and quality control processes.[298]

The NGF proposed that the development of an information resource should be pursued incrementally so as avoid creating an unnecessary reporting burden upon NEMMCO.[299]

ETNOF was concerned that TNSPs may be held legally liable for the decisions of participants who rely on the information.[300] ETNOF suggested the Rules should limit TNSP and NEMMCO liabilities to third parties. This would reduce customer

---

295 NGF, Draft Report submission, p.9; CS Energy, Draft Report submission, p.3; EUAA, Draft Report submission, p.29; Origin, Draft Report submission, p.1.

296 EUAA, Draft Report submission, pp. 27-8

297 NEMMCO, Draft Report submission, pp. 7-8

298 Hydro Tasmania, Draft Report submission, p.3

299 NGF, Draft Report submission, p.9

300 ETNOF, Draft Report submission, p. 2

costs and act a an incentive for TNSPs to provide information more freely. ETNOF also noted that significant effort is required by TNSPs to fulfil an obligation to publish data for a large number of flow paths.[301]

In our final recommendation, we recommend that NEMMCO must develop and publish information that enables market participants understand patterns of network congestion. This includes information to help predict the nature and timing of events that are likely to affect materially what constraints NEMMCO uses in dispatch. This information will be included in a dedicated CIR, which will also include information on mis-pricing (discussed next). In finalising this recommendation, we considered the issues and suggestions raised in submissions. These comments informed how we propose to implement this recommendation, discussed in section C.6.4.

C.6.3.1 Information on the incidence and patterns of mis-pricing

In the Directions Paper, we suggested that NEMMCO could publish information on the mis-pricing[302] of generation to enable participants to better manage congestion in the medium to long term. We suggested that this information could:

- be in the form of published nodal prices *or* differences between the RRP and nodal prices;
- identify whether the constraint that caused the mis-pricing was an outage constraint or a system normal constraint; and
- identify the network element or cut-set on which the limitation arose.[303]

Responses from submissions were varied.

The Southern Generators supported the publication of nodal prices. However, they expressed concern that potential entrants may be unfamiliar with the idiosyncrasies of NEM pricing and may not appreciate that generators are not actually settled at their nodal price; therefore the publication of mis-pricing data ought to be accompanied by explanation to ensure it is not misinterpreted.

Powerlink expressed concern that any obligation to provide information should not expose the TNSPs to the risk of being held responsible for the wisdom of investment decisions made by new investors.

Regarding the publication of nodal prices, NEMMCO thought this would require a substantial ongoing commitment of resources.[304] It suggested that information on

301 ETNOF, Draft Report submission, p. 5

302 The concept of mis-pricing is described in chapter 2 of this Review's Final Report and Appendix A

303 AEMC, Congestion Management Review, Directions Paper, 12 March 2007, p.60.

304 Nodal prices are calculated as the marginal cost of supply at each node (refer to Appendix A for a more detailed explanation of nodal pricing). To determine accurately all nodal prices in the NEM, NEMMCO would probably need to run a full-network dispatch and pricing model in parallel to the current dispatch model.

mis-pricing based on constraint shadow prices would be simpler to produce and just as useful to market participants. NEMMCO also noted that it already publishes substantial information on constraints and that there would be merit in exploring how the provision of further data on mis-pricing could be expected to improve participants' responses to congestion.

The routine publication of mis-pricing information will be valuable in identifying specific points of congestion, where targeted measures, like network support agreements, could be implemented to assist in the management of congestion. Mis-pricing information will assist participants in identifying areas where they themselves can negotiate such agreements.

Investors will also find value in mis-pricing information as a tool in their decision-making processes. While investment locational decisions are based on a range of factors including access to fuel and water and environmental considerations, access to transmission is also important. Information on mis-pricing will help inform investment location decisions, identifying possible congested areas and therefore prompting a comprehensive assessment of congestion at a preferred location.

In the Draft Report we recommended that NEMMCO develop a methodology in consultation with participants for the production of mis-pricing information that covers all material congestion in the NEM. We recommended that this information be published on a quarterly basis, and that NEMMCO's other resource commitments be taken into account when establishing the commencement date.

All submissions to the Draft Report[305] supported the recommendation, saying that it would improve transparency in the production of mis-pricing information[306] and would be more indicative of the materiality of mis-pricing.[307] Hydro Tasmania suggested using working groups in the consultation phase.[308]

As to the commencement date for the development of a methodology and publication of mis-pricing information, EUAA did not support the proposal that NEMMCO be able to vary the date based on its resource commitments.[309] Instead, its view was that NEMMCO must produce this information in accordance with the Rules. EUAA was the only submission on this particular point.

We are subsequently recommending that NEMMCO publish information on the extent and pattern of mis-pricing as part of a single, comprehensive Congestion Information Resource. After consideration of submissions, the specifics of how NEMMCO should publish mis-pricing information and when it should start will be subject to stakeholder consultation. We set out the details of how to implement this recommendation in the following section.

---

305 Origin Energy, CS Energy, InterGen, NGF, Hydro Tasmania Draft Report submissions.

306 CS Energy, Draft Report submission, p.3.

307 EUAA, Draft Report submission, p.29.

308 Hydro Tasmania, Draft Report submission, p.3.

309 EUAA, Draft Report submission, p.29.

C.6.4 Final recommendations and implementation

We recommend that NEMMCO be required to publish a single, central resource for congestion-related information—the CIR. The objective of the CIR:

> "is to provide information in a cost effective manner to Market Participants to enable them to understand patterns of network congestion and make projections of market outcomes in the presence of network congestion."

This will provide information on planned network events, informing market participants about which constraint equations NEMMCO will use in dispatch. The CIR will also include historical information on the occurrence and materiality of all mis-pricing in the NEM caused by congestion.

Better information about which constraint equations will be included in dispatch will improve participant decision making. The CIR will provide the most up to date information on network outages and other planned network events. This will provide participants with a better understanding of how potential changes in system conditions are likely to affect network constraints and therefore influence dispatch. Improvements in information will translate into more informed an deficient decision making for participants.

The more frequent and regular publication of information on the prevailing patterns of congestion under different network conditions, e.g. in the presence of outages, and under system normal conditions, will also help policy makers and market participants understand patterns and trends in the incidence of congestion. This can inform participants' contracting and investment decisions and thereby assist congestion management in the longer term. Furthermore:

- Planned network events must include, at a minimum: network outages; connection and disconnection of generating units or load; commissioning (or decommissioning) of network assets or new or modified NCAS; and NSAs.
- NEMMCO must publish this resource on a timely basis and must publish updates as soon as practicable.
- In developing or modifying this CIR, NEMMCO must consult with stakeholders.
- The CIR is a continually evolving source of information for the market.
- TNSPs and other Registered Participants are obliged to provide information requested by NEMMCO to develop this resource.

Implementation

The *Draft National Electricity Amendment (Congestion Information Resource) Rule 2008* (CIR Draft Rule) can be found in Appendix G.

We have adopted an objectives-based approach to the implementation of the CIR. By this we mean that in the CIR Draft Rule we have:

- removed the current high level of prescription in the Rules dictating exactly what information NEMMCO and TNSPs must provide; and

- replaced this with a high-level objective (clause 3.7A(a), specify guidelines (clause 3.7A(k)), and the outline of a process by which the CIR can be amended subject to stakeholder consultation (clauses 3.7A(l) and (m)).

This will allow NEMMCO, TNSPs, other information providers, and those who use the information, to determine the most beneficial sources of information, the most appropriate form of publication, and an efficient publication timetable.

The CIR Draft Rule stipulates that the CIR must be a source of information on: (1) planned network events that are likely to materially affect network constraints; and (2) historical data on mis-pricing in the NEM.

Following submissions on the Exposure Draft of this Rule[310], the definition of "mis-pricing" has been amended. Mis-pricing is now defined as the difference between the RRP and an estimate of the marginal value of supply.

We do not expect this objective to be attained in the first CIR to be published. Instead, as a transitional arrangement, we require of this initial CIR only that it formalise the provision of information on planned network events currently published by NEMMCO and TNSPs (rule 11.X).[311]

NEMMCO expressed concern that aspects of the interim CIR (published under 11.X) were unclear.[312] These have now been addressed. In particular, clause 3.7A(c) now states that the CIR must contain the same level of detail as the interim CIR. Clause 3.7A(d)(3) now requires NEMMCO to amend the CIR where such an amendment furthers the CIR objective. Finally, under clause 11.X.2(a), the development of the interim CIR is exempt from following the Rules consutation proceedure.

Grid Australia commented that the draft Rule might be construed to mean that TNSPs are required to undertake works planning two years in advance. This is not necessary and clauses 11.X.1 and 11.X.2(h)-(j) make this clear.

ETNOF expressed a concern that network businesses may be liable for the information they provide to the market. The CIR Draft Rule takes this into account: proposed clause 3.7A(p) states explicitly that any information provided to the market is the "best estimate" of the information provider. However, the proposed Rule also places the onus on the information provider to ensure that they provide the most up-to-date information to the market in a timely fashion ("as soon as practicable") (clauses 3.7A(n) to (p)).

Clause 3.13.4(y) includes a requirement that NEMMCO publish the CIR in accordance with "the timetable" in the Rules.

---

310 AEMC 2008, Congestion Management Review, Exposure Draft, March 2008, Sydney. Available: www.aemc.gov.au.

311 See section C.6.1 for a list of the existing sources of information.

312 NEMMCO, submission on Exposure Draft, 15 April 2008.

It is for NEMMCO to determine whether or not the most productive process for undertaking consultation includes convening an industry working group.

C.7 Terms of Reference

While most of the submissions to the Draft Report implicitly accepted our interpretation of the Ministerial Council of Energy's Terms of Reference, the ERAA thought that we took a narrow view. It proposed that a wider and more comprehensive examination of transmission pricing and development rules should have been undertaken.[313]

EUAA also had concerns about our interpretation of the Terms of Reference. It stated that we introduced a concept of "feasibility" in interpreting the Terms of Reference. It did not consider that the Draft Report sufficiently analysed the impacts of congestion on either end users or retailers in terms of final delivered prices.[314]

Discussion

In undertaking this Review, we undertook three rounds of general consultation and a number of supplementary consultations on specific issues. We considered a range of related reviews and Rule changes that addressed congestion related issues to ensure a co-ordinated comprehensive assessment of the issues we and stakeholders identified. We also considered all our recommendations against the National Electricity Objective, which is directed at promoting efficient outcomes for consumers of electricity.

[313] ERAA, Draft Report submission, p.1

[314] EUAA, Draft Report submission, p.11

C.8 Evidence base / Approach to analysis

There was considerable debate in submissions to the Draft Report about our conclusions on the materiality of congestion

Some submissions supported our conclusions, agreeing that having resolved the congestion problem in the Snowy region, the outstanding level of congestion in the NEM was relatively immaterial.[315] These submissions therefore supported the recommendations put forward in the Draft Report, agreeing they were proportionate and incremental relative to the degree and materiality of congestion.

Several submissions were critical of the materiality findings. The main issue was our considerations of dynamic efficiency. Many submissions considered that this measure of longer term materiality was insufficiently address, which in their view, let to an erroneous conclusion that congestion was not a material problem. Another concern was that our historical analysis of productive efficiency measures did not effectively project future changes in congestion.

The ERAA, "the Group", Hydro Tasmania, Babcock and Brown Power, the Government of South Australia and the EUAA all considered additional analysis on dynamic efficiency effects was necessary in order to determine whether or not congestion was a material problem. While many of them noted the difficulties in measuring dynamic efficiency gains, they considered congestion was growing and this was not evident in the historical analysis presented.[316]

"The Group" focused on our interpretation of the IES report, which attempted to measure the dynamic efficiency benefits of increasing the degree of locational pricing in Queensland.[317] It argued that, notwithstanding our concerns about the report produced, it should not have been dismissed as it showed that there were demonstrable dynamic efficiency gains to be made.

VENCorp was concerned that analysis of the data skewed results to show that congestion was immaterial. It stated that the appropriate way to measure the materiality of congestion was to compare congestion costs against estimated costs of implementing measures to remove or relieve congestion.[318]

Some submissions said that failing to improve generator access rights to the transmission network would lead to material congestion.[319]

---

[315] Snowy Hydro, Draft Report submission, p.1; ETNOF, Draft Report submission, p.1; Macquarie Generation, Draft Report submission, p.1.

[316] ERAA, Draft Report submission, p.3; "the Group" Draft Report submission, p.2; Hydro Tasmania, Draft Report submission, p.2; Babcock and Brown Power, Draft Report submission, p.5; Government of South Australia, Draft Report submission, p.1; EUAA, Draft Report submission, p.12.

[317] Loy Yang Marketing Management Company, AGL Energy, International Power, Flinders Power, InterGen Australia and Hydro Tasmania, Draft Report, submission, pp.2-3.

[318] VENCorp submission, p.1.

[319] NGF, Draft Report submission, p.2; InterGen, Draft Report submission, p.1; The Group, Draft Report submission, pp.15-17.

Other submissions posed that even if congestion did not appear to be a material problem today, it had the potential to increase dramatically with time. Therefore, the market required a location-specific interim constraint pricing mechanism to be able to manage congestion if and when it arose.[320]

Discussion

For this Review, we undertook an evidence-based approach to evaluating the materiality of congestion. In the Draft Report, we highlighted the need to consider the impacts of congestion on productive (dispatch) efficiency, risk management and forward contracting, and dynamic efficiency.

Our recommendations have been informed by relevent evidence on the prevalence and materiality of congestion in the NEM. Much of this evidence is based on experience in the recent past. While this type of evidence can provide valuable insights, it also has limitations. We need to be aware of the possibility that patterns of congestion might materially change in the future, and seek to identify and understand the drivers for any such changes.

The available evidence also needs to be interpreted carefully. Over the short and long term, we looked at the prevalence, duration, and location of congestion as well as economic cost indicators. It is important to consider both prevalence and economic cost. A high incidence of congestion does not necessarily have a material market impact. On the other hand, an infrequent point of congestion may have a significant impact on market dispatch. To get a complete picture of congestion in the NEM, we looked at a range of congestion measures.

We need to recognise and seek to understand both the short-term and the long-term implications of congestion, especially in light of the significant amount of planned energy investment over the next five to fifteen years. We considered several approaches and data sources. We have also considered future market developments and the potential impact on the materiality of congestion, and what the pressures might be on the current Rules and regulatory framework in this context including informed by submissions from market participants.

The CM Regime we recommend in this Final Report, including our recommended changes, represents an efficient and proportionate framework for managing congestion. However, we are aware that there are a range of factors shaping the future development of the NEM that, collectively, will put new and different pressures on the CM Regime. The two most obvious factors are:

- the general tightening of balance between supply and demand, with continuing strong growth in the demand for electricity and a smaller rate of growth in the supply of new generation capacity; and

---

320 Origin Energy, Draft Report submission, p.1; ESAA, Draft Report submission, p.1; ERAA, Draft Report submission, p.3.

- policy responses to climate change, such as an ETS and MRET scheme, which will change significantly the underlying economics of the market and will influence short-term and long-term behaviour in the market.

We have a statutory role in respect of market development. It is therefore important and appropriate for us to consider, more broadly and on an ongoing basis, whether the current market design and Rules are likely to continue to promote efficient outcomes for consumers in the light of these new developments. This consideration includes, but is wider than, the details of the CM Regime. There are many interactions between changes to the CM Regime and changes to others aspects of the regulatory framework, and partial assessment runs the risk of unintended consequences and less efficient outcomes.

We therefore considered these issues in more detail and highlighted interactions between other related policy initiatives, such as the establishment of a NTP and reform of the current regulatory test for transmission investment decisions in chapter 4 of this Final Report. We also documented some of the options that might have relevance to this debate, including options for change which have been raised by stakeholders through the course of the Review but which, in our view, fell outside the scope of this Review.

D Outlook for future trends in congestion

D.1 Introduction

This appendix discusses a range of issues related to the future trends in congestion:

As discussed throughout this Final Report, while the evidence indicated that the level of congestion had not been significant in the past, it is likely to differ in the future. There are many factors that can influence future trends in congestion. In this appendix we provide information on:

- forecast changes in demand and supply in each of the NEM regions (section D.2);
- changes to the dispatch of intermittent generation, like wind farms (section D.3); and
- key aspects of Australia's policy response to climate change, like the Garnaut Review, design of an Emissions Trading Scheme (ETS) and Mandatory Renewable Energy Targets (MRETs) (section D.4).

In addition, in section D.5, we also present a summary of three proposals presented in submissions to the Draft Report that seek to address the dis-orderly bidding problem, a congestion-related policy challenge arising for the NEM's regional pricing design. We describe these proposals, as presented by their proponents, because while they may not be proportional responses to the past level of congestion in the NEM, there may be scope in the future to consider options like these.

They are presented in this appendix to provide an information resource for future reference. We do not provide any commentary on or support for any of the proposals.

D.2 Forecast changes in demand and supply

In its 2007 Comprehensive Reliability Review (CRR) Report, the Reliability Panel observed that the NEM had historically performed well at meeting demand reliably. It commented, however, that historically, this was supported by surplus generation capacity in some regions.[321] NEMMCO projections for the NEM's supply-demand balance are not as generous going forward.

In the 2007 Statement of Opportunities (SOO), NEMMCO estimates supply shortfalls for Queensland in 2009/10, Victoria and South Australia (combined) in 2010/11, and NSW in 2013/14. NEMMCO does not project any shortfalls for Tasmania over the next ten-year period.[322]

In addition, the Reliability Panel noted that the nature of supply and demand in the NEM had undergone a significant change since the NEM started in 1998. It noted, for example, an increasingly peaky demand profile and a shift in the mix of generation plant including an increased contribution from intermittent sources like wind generation.[323]

These projected shortfalls along with the need to supply greater levels of peak demand will directly affect the type (both technology and fuel) and timing of new generation investment. The location of this new generation can affect the prevalence of congestion on the network. The existing location pricing signals for generation will facilitate the efficient investment and locational decisions of the new supply.

The below sections present a summary of regional supply and inter-regional transfer conditions.

D.2.1 Intra-regional supply conditions

D.2.1.1 Queensland

In the 2007 SOO, maximum energy demand in Queensland is forecast to increase by an average of 3.3% in winter and 3.6% in summer (under a medium growth scenario) per year over a 10 year period, which is higher than any other region in the NEM. Over the same period, the scheduled energy is projected to increase by an average of 3.6% per year (medium growth scenario).

In the Queensland region, there are a number of proposed generation projects which are expected to be commissioned between 2008 and 2009. In the Southwest region, there are proposed generation plants in Spring Gully (1 000 MW), Chinchilla (242

---

[321] AEMC Reliability Panel 2007 (Reliability Panel), Comprehensive Reliability Review (CRR), Final Report, December 2007, Sydney, p.xi.

[322] NEMMCO, 2007 Statement of Opportunities, pp."2-9", "2-10", "2-12", and "2-13".

[323] Reliability Panel, 2007 CRR, p.x.

MW) and Braemar (up to 480 MW). In the Central West region, there are projects for new generation in Stanwell Energy Park of up to 640 MW.

There are a number of existing areas within Queensland where transfer capability is tight, and this increasing demand and new generation will place more pressures on the Queensland network. In response to this, Powerlink have been given a total capital expenditure over the next five years of $2.6 billion.

The staged Central to North Queensland (CQ-NQ) transmission project due for completion between 2007 and 2009 will improve transfer capability to meet forecast electricity demand in North Queensland.

The Central Queensland to South Queensland (CQ-SQ) limit bound for 4.7% of the time over the summer period due to the capacity across this grid section being fully utilised during opportunities to export electricity to NSW. Commissioning of new generating plant in Southern Queensland since the 2006/07 summer is expected to reduce flows on this grid section in the 2007/08 summer; however this may be affected by reductions in generation due to water shortages.

The Tarong limit in South Queensland experienced minor binding over the 2006/07 summer. To keep pace with the high load growth in South East Queensland, the Middle Ridge to Greenbank transmission reinforcement along with additional shunt compensation has been committed for the 2007/08 summer.

In 2006/07 the Gold Coast limit bound for around 11% of the time during winter and 0.7% of the time during summer. Even though Powerlink completed a project, in late 2006, to increase the transfer capability of the Gold Coast grid section, binding events on this grid section occurred during periods when spare capability across this grid section was fully utilised by the Terranora interconnector transferring power into NSW. Powerlink has committed projects underway that increase the transfer capability of the Gold Coast grid section to meet forecast load growth in the Gold Coast and Tweed Heads areas.

D.2.1.2 NSW

Maximum energy demand in NSW is forecast to increase by an average of 2.1% in winter and 2.5% in summer (under a medium growth scenario) per year over a 10 year period. Over the same period, the scheduled energy is projected to increase by an average of 1.6% per year (medium growth scenario). Over the period 2004/05 to 2008/09, TransGrid has a fixed capital allowance of $1.188 billion. Proposed expenditure for the period post 2008/09 has not yet been announced.

Throughout NSW, there are a number of gas turbine generation projects planned, such as Munmorah (600 MW, expected to be operational between 2009 and 2010) and Tomago (500 MW) on the NSW Central Coast. Also in this area, there are plans for an upgrade and development of the Eraring Power station (up to 3 040 MW, operational in stages from 2009). In the South East of the state, there are planned gas turbine developments for Bamarang (300 MW by 2010/11) and Marulan (300 MW by 2010/11). An upgrade to the existing Mt Piper power station in the Central West area (to 750 MW each for Unit 1 and 2) is planned for 2008 and in the South West, there is a proposal for a gas fired plant at Uranquinty (640 MW, by summer 2008/09).

TransGrid are proposing to progressively complete a high capacity ring linking the Sydney, Newcastle and Wollongong load centres with major generating centres located in the Central Coast, Western coalfields and Hunter Valley. To date the Eraring – Kemps Creek 500 kV line has already been developed. TransGrid are currently committed to the process of converting the existing Bayswater – Mt Piper and the Mt Piper – Marulan lines, which presently operate at 330 kV, to operate at their design voltage of 500 kV. For the summer of 2008/09 Transgrid has proposed to develop up to 350 MW of network support capability for the Newcastle-Sydney – Wollongong area.

The mid-north coast area of NSW has a number of current and emerging constraints primarily as a result of population growth and therefore high load growth. TransGrid is proposing a project to relieve this concern. These works are expected to cost around $62 million and to be completed by mid 2009.

Central Western Sydney is also experiencing high load growth. TransGrid has proposed a new transmission line between Wollar and Wellington to meet this increasing demand. This project is expected to cost $30 million and could be completed by 2010.

D.2.1.3 Victoria

In Victoria, maximum energy demand is forecast to increase by an average of 0.8% in winter and 1.8% in summer (under a medium growth scenario) per year over a 10 year period. Over the same period, the scheduled energy is projected to increase by an average of 1.0% per year (medium growth scenario). SP AusNet proposes that its capital expenditure for the 2008/09 to 2013/14 period will be $928 million. A final decision by the AER regarding this proposal has not yet been made.

There are three major generation projects planned for this region. In the Northern corridor a 130 MW hydro station is planned for the Kiewa area. In the Eastern corridor, an upgrade to the Loy Yang A station is planned and will result in increases up to 100 MW. In the South West corridor, a 1 000 MW gas-fired station is planned near Mortlake.

To support load growth in and around the Melbourne metropolitan area, VENCorp has committed projects underway which will improve the reliability of supply to this region. In its 2007 APR, VENCorp indicated that the committed development of the South Morang Terminal station (expected to be completed early 2009) would help to meet these requirements.

There are a number of constraints that can occur in the Northern corridor, which comprises the Victorian side of the Victoria to Snowy-NSW interconnection. However, in the 2007 APR, VENCorp states that the market benefits associated with the management of the constraint over the next 5 years are insufficient to justify augmentation. Though not yet formally proposed, VENCorp has identified options, such as line up-rating, new transmission lines or wind monitoring schemes, that may become justifiable in the longer term (between 6 and 10 years).

In the Greater Melbourne and Geelong areas, there are a number of smaller constraints as a result of transmission element outages, increased load and changes to generation. In the short term, VENCorp is seeking to economically manage these risks, at least until approximately 2011/12.

Throughout regional Victoria, there are a number of constraints as a result of transmission element outages, high load and bulk power transfer. However, VENCorp states that the market benefits from the alleviation options, such as line up-rating, are insufficient to justify augmentation and that they believe the constraints can be economically managed for the next 4 to 5 years.

D.2.1.4 South Australia

Maximum energy demand in South Australia is forecast to increase by an average of 1.8% in winter and 2.1% in summer (under a medium growth scenario) per year over a 10 year period. Over the same period, the scheduled energy is projected to increase by an average of 1.5% per year (medium growth scenario). Over the next five years, ElectraNet has forecast a capital requirement of $778.1 million. Growth in demand is driving the need for significant transmission investment to meet mandated reliability standards specified in the Rules and the Electricity Transmission Code (ETC).[324] A final decision by the AER regarding this proposal has not yet been made.

There are a number of conventional generation projects under consideration in South Australia. The most advanced of these is the 120 MW gas-fired power station announced recently by Origin Energy for construction adjacent to Quarantine Power Station on Torrens Island, which is expected to be operational prior to the 2008/09 summer.

Three new wind farms are currently being built in the State: Lake Bonney Stage 2, the Bluff at Hallett, and Snowtown. These wind farms are all at various stages of construction and, when complete towards the end of 2008, will lift the total wind capacity in the State to 742 MW.

While still a net importer of electricity, South Australia has imported less, and exported more electricity than ever before over the 2006/07 year. Increasing volumes of wind energy and higher interstate forward contract prices, the latter as a result of capacity risks associated with the drought, are the two primary causes of the change in import/export balance.

---

324 New reliability standards resulting from a recent review of the ETC by state regulator ESCOSA also require additional investment. For example, the mandated reinforcement of the Adelaide CBD is expected to cost approximately $138 million during the forthcoming regulatory period. This is a major project and the most significant single reason for the higher capital expenditure requirement in the forecast period (there has been no project of this significance or magnitude in the current regulatory period).

D.2.1.5 Tasmania

In Tasmania, maximum energy demand is forecast to increase by an average of 1.5% in winter and 1.6% summer (under a medium growth scenario) per year over a 10 year period. Over the same period, the scheduled energy is projected to increase by an average of 1.6% per year (medium growth scenario). Transend has a fixed capital expenditure allowance of $306.8 million for the five and a half year period 2004 to 2008/09. The major capital expenditure project for this period is the works being completed in the south of the state, including the Waddamana and Risdon Vale line (see below), estimated to cost $55 million. Proposed expenditure for the period post 2008/09 has not yet been announced. In the recent SOO[325], NEMMCO noted that there were no new generation projects planned for Tasmania.

The most common constraint in the Tasmanian region is that of thermal constraints. To alleviate this problem, Transend use real time measurements to give dynamic real time line ratings.

One of the major problems in the Tasmanian region is the high demand in the Hobart area. This problem has previously been managed by using a number of NSAs. A major project currently being undertaken by Transend is that of the replacement of the existing transmission line between Waddamana and Risdon Vale with a new higher capacity line to improve power supply to Hobart and Southern Tasmania. This project is due for completion mid 2009. This project will lessen the need for the use of NSAs to meet demand in the south.

D.2.2 Inter-regional transfer conditions

D.2.2.1 Queensland—NSW (QNI and Directlink)

It is recognised that the current transfers of 500 MW north and about 1 100 MW south on QNI will be impacted by the imminent opening of Kogan North Power station, with NSW exports being reduced.

The commissioning of the NSW 500 kV ring upgrade should help to relieve congestion on QNI through increasing capability in the Northern NSW network.

A QNI upgrade is expected to improve reliability in both states, enable higher interchange when the supply/demand balance is tightening, and reduce the occurrence and size of constraints on QNI. Options being considered range from line series compensation and voltage support at a cost of $100-$120 million with a 300-400 MW increase in capacity to new line development at a cost of $600-$800 million and a capacity increase of up to 1 000 MW.

In its APR,[326] Powerlink says it expects that studies on the possible augmentation of the QNI interconnector will have progressed to the stage where Powerlink and

[325] NEMMCO, Statement of Opportunities for the National Electricity Market, October 2006.
[326] Powerlink, Annual Planning Report, 2006.

TransGrid will report the outcomes of the detailed technical and economic studies within the later part of this year. Currently the optimal timing for the QNI upgrade is 2011 (compared to the 2009 timing indicated by earlier pre-feasibility studies). Commitment of additional new generation in NSW (or further south) may further defer the timing of a QNI upgrade. Conversely, the commitment of new generation within Queensland may bring forward the optimum upgrade timing.

D.2.2.2 Snowy—NSW

The transfer limit on the Snowy to NSW interconnector was increased by 200 MW during daylight hours in January to April. This increase is the result of a NSA put in place by Snowy Hydro, industrial loads, and Transgrid. This arrangement is an Automated Control scheme whereby loads and generation can be rapidly offloaded in the event of a trip in a transmission line making up the Snowy to NSW interconnector.[327] This should help to relieve the increasing congestion on the flow northwards from Snowy.

D.2.2.3 Victoria—Snowy

VENCorp has recently committed to an augmentation of the South Morang terminal station. These works at South Morang will improve Victorian export transfer capability hence improving flows between the Victorian, South Australian and Snowy regions. Work is currently being undertaken to develop the South Morang Terminal Station including the establishment of a switchyard and the installation of two transformers. This work will see the transfer of load from Thomastown terminal and Somerton power station. This project will help to meet Melbourne's long term supply requirements and is planned for completion early in 2009.

In the 2007 APR, VENCorp indicated that there was no justifiable solution to the loading on the Dederang – South Morang line in the short term (i.e. 5 year outlook). While options exist to solve this problem, such as the uprating of the lines or the installation of a third line between Dederang and South Morang, the market benefits associated with these options are insufficient to justify augmentation. VENCorp believes that the system normal constraints associated with this line can be economically managed until at least 2011/12.

[327] NEMMCO Communication No. 2356 – Change in SNOWY1 Interconnector Transfer Limit.

D.3 Wind farm generation

The amount of intermittent generation participating in the NEM has grown rapidly over the last few years, particularly wind farm development in South Australia. This trend is expected to continue, supported by the financial incentives made available through various government renewable energy initiatives. The increasing penetration of intermittent generation affects NEMMCO's ability to efficiently manage power system security, and hence can influence the incidence of binding constraints in the NEM. Evidence suggests that the wind farm development in South Australia has lead to increased binding on the Heywood Interconnector.

Since the start of the NEM all generation with an intermittent output has been able to be classified as non-scheduled under the Rules. Non-scheduled generation is hence exempted from control by NEMMCO's central dispatch, on the basis that its electrical output cannot be controlled "on demand" as its available energy source is inherently uncontrollable. Non-scheduled generation therefore effectively has firm network access and dispatch priority over scheduled generation unless and until directed by NEMMCO or its agents to operate otherwise. This leads to the risk of non-scheduled generation overloading a network element. To mitigate against this risk of violating network limits, NEMMCO may be required to increase the operating margin for network limits in order to create more spare transfer capacity. This will reduce the allowed flow on the network limit which will increase the probability of the constraint binding.[328]

At the moment, wind farms with an aggregate nameplate rating of ≥ 30 MW accounted for 611 MW of the total installed wind farm generation in the NEM, with 388 MW in South Australia, 83 MW in Victoria, and 140 MW in Tasmania.

In addition there is a further 5 185 MW of significant wind farm generation across the NEM that is either under construction, with or seeking planning approvals or subject to feasibility studies, as follows:

- South Australia: 344 MW under construction, 610 MW with planning approval, and 890 MW in feasibility stages (total 1 844 MW);
- Victoria: 357 MW under construction, 725 MW with or seeking planning approval, and 667 MW in feasibility stages (total 1 749 MW);
- Tasmania: 130 MW with planning approval, and 190 MW in feasibility stages (total 320 MW);
- NSW: 581 MW with or seeking planning approval, and 515 MW in feasibility stages (total 1 096 MW); and
- Queensland: 124 MW with planning approval and 52 MW in feasibility stages (total 176 MW).

328 Network operating margins are generally implemented as a static value on the RHS of the constraint equation, and apply at all times that the relevant network constraint equation is invoked.

In South Australia alone, the currently installed plus future committed wind farm projects (those under construction or with planning approvals) would amount to a total installed capacity of 1 342 MW, or around 40% of the total South Australian generating capacity of 3 260 MW assumed available for summer 2006/07.

Generation from wind farm developments is likely to have a significant and growing influence over the operation of the NEM in the foreseeable future, and is therefore likely to have an increasing influence on the level of binding constraints in the NEM.

However, the market is aware of these issues. On 23 April 2007, we received a Rule change proposal from NEMMCO that attempted to address the problems of intermittent generation on network limits. The Rule change proposal sought to require significant intermittent generators (such as wind farms) to participate in the central dispatch and Projected Assessment of System Adequacy (PASA) processes, and limit their output at times when that output would otherwise violate secure network limits.

In its Rule change proposal, NEMMCO presented evidence on the incidence on binding network constraints equations involving significant intermittent generation for the six month period from 1 March 2006 to 31 August 2006 in the South East area of South Australia. NEMMCO concluded that in this area, wind farm generation has materially contributed toward the MW amount of network congestion in that area, resulting in constraining off interconnector flows into South Australia and (to a lesser extent) constraining off local scheduled generation involved in those constraints.

On 1 May 2008, we published our final Rule determination on this proposal and made the *National Electricity Amendment (Central Dispatch and Integration of Wind and Other Intermittent Generation) Rule 2008 No. 2*. Scheduled 1 of the Rule commenced on 1 May 2008. Scheduled 2 of the Rule will commence on 31 March 2009.

In making this final Rule determination, we largely adopted NEMMCO's proposal with some modifications to simplify the Rules applying to intermittent generators to reduce the regulatory and compliance costs on those generators. The key elements of the Rule as made are to:

- require new intermittent generators to register under the new classification of Semi-Scheduled Generator;
- require Semi-Scheduled Generators to participate in the central dispatch process, including submitting offers and limiting their output to below a dispatch level whenever the generation is limited by the central dispatch process; and
- include grandfathering provisions for intermittent generators registered at the date the final Rule determination is published and projects considered committed at 1 January 2008.

D.4 Australian policy response to climate change

Australia is investigating how it can best respond and adapt to climate change. The following sections summarise what Australia's climate change policy objective is, why it is important, and how it intends to meet the objective.

D.4.1 What is the climate change policy objective?

The policy objective is for Australia to respond effectively to the consequences of climate change (or an enhanced greenhouse effect) by implementing a mixture of mitigation and adaptation strategies along with international collaborative efforts.

D.4.2 Why is this objective important?

Among the developed world, Australia is one of the most vulnerable to the impacts of climate change. This reflects Australia's already variable climate, poor soils, vulnerable ecosystems and high proportion of population living in coastal areas. Thus the potential impacts of climate change and the need to develop appropriate adaptation strategies are now important considerations in the context of national, state and local government responses to the issue.

According to the federal government, there is little doubt that Australia will face some degree of climate change over the next 30 to 50 years irrespective of global or local efforts to reduce greenhouse emissions. The scale of that change, and the way it will be manifested in different regions is less certain, but climate models can illustrate possible effects.[329]

Climate change will alter climatic variables such as mean temperature and the likelihood of extreme climactic events. The climate change variables may directly or indirectly impact upon government and business. The risks (both the likelihood of occurrence and the extent of consequences) need to be strategically managed to successfully adapt to the impacts of climate change.

The Australian government's view is that the cost to business for failing to act will be far greater than if responsible action is taken now.

D.4.3 How will this policy be implemented?

The Australian government proposes three pillars in climate change policy- helping to shape an international solution, reducing Australia's emissions, and adapting to the climate change we cannot avoid.[330]

---

[329] Australian Greenhouse Office, Department of the Environment and Heritage, Climate Change: Risk and Vulnerability, Promoting an Efficient Adaptation Response in Australia - Final Report, March 2005.

[330] Senator Hon Penny Wong, It's official- Australia is now part of the Kyoto Protocol, 11 March 2008.

To achieve the policy objectives, the Australian government has committed to the following:[331]

- to reduce emissions to 60 per cent of 2000 levels by 2050;
- implementing a comprehensive emissions trading scheme by 2010;
- setting a 20 per cent renewable energy target by 2020; investing in research and development of low-emissions technologies;
- helping households and businesses to use energy more wisely; and
- managing land to reduce emissions.

The Australian government intends to use a market mechanism to lower emissions at the lowest cost to the economy and to households

The Australian government proposes to devise measures to assist households, particularly low-income households to adjust to the impact of carbon prices.

D.4.3.1 What is the Garnaut Climate Change Review?

On 30 April 2007, the Australia's State and Territory Governments commissioned Professor Ross Garnaut to conduct an independent study on climate change (the Garnaut Review). In January 2008, the Prime Minister of Australia confirmed the Commonwealth Government's participation in the Garnaut Review.

The Terms of Reference requested Professor Garnaut to report on:[332]

1. the likely effect of human induced climate change on Australia's economy, environment, and water resources in the absence of effective national and international efforts to substantially cut greenhouse gas emissions;
2. the possible ameliorating effects of international policy reform on climate change, and the costs and benefits of various international and Australian policy interventions on Australian economic activity;
3. the role that Australia can play in the development and implementation of effective international policies on climate change; and
4. in the light of 1 to 3, recommend medium to long-term policy options for Australia, and the time path for their implementation which, taking the costs and benefits of domestic and international policies on climate change into account, will produce the best possible outcomes for Australia. In making these recommendations, the Review will consider policies that: mitigate climate change, reduce the costs of adjustment to climate change (including through the

---

331 www.climatechange.gov.au

332 Garnaut Climate Change Review, Terms of Reference, 30 April 2007. Available: http://www.garnautreview.org.au/CA25734E0016A131/pages/about.

acceleration of technological change in supply and use of energy), and reduce any adverse effects of climate change and mitigating policy responses on Australian incomes.

The Garnaut Review final report is due on 30 September 2008.

Interim Report – February 2008

In his February 2008 Interim Report, Professor Garnaut stated that mainstream scientific opinion and the Garnaut Review's own work:

> suggest that the world is moving towards high risks of dangerous climate change more rapidly than has generally been understood. This makes mitigation more urgent and more costly.[333]

Australia must start to put in place effective policies to achieve major reductions in emissions. Professor Garnaut places an ETS at the centre of an Australian emissions mitigation strategy.[334] An ETS places a cap on total emissions, issues permits for those emissions, requires participants to hold permits for any generated emissions, and allows trading of permits.

D.4.4 What are the emissions mitigation strategies?

The Australian government proposes to implement an emissions trading scheme to commence in 2010. Emission trading will place a limit or "cap" on the emissions allowed to be produced.

Australia signed the Kyoto Protocol in December 2007 and it would take effect on March 2008. Under Kyoto, Australia is obliged to limit its greenhouse gas emissions in 2008/12 to 108 per cent of its emissions in 1990.

According to a report titled "Tracking to the Kyoto Target", by 2020, Australia's emissions will be 120 per cent of 1990 levels. That is a reduction of 38 million tonnes on the 2006 forecast of 127 per cent.

D.4.4.1 Mandatory Renewable Energy Target (MRET)

To help ensure the Government achieves its goal of a 20 per cent share for renewable energy in Australia's electricity supply by 2020, the Government committed to increasing the MRET from 9 500 gigawatt-hours to 45 000 gigawatt-hours in 2020.[335]

---

333 Professor Ross Garnaut, Interim Report to the Commonwealth, State and Territory Governments of Australia(Interim Report), Garnaut Climate Change Review, February 2008, p.4. Available: www.garnautreview.org.au.

334 Garnaut, Interim Report, p.5.

335 Australian Government, Department of Climate Change, 20% Renewable Energy Target. Available: http://www.climatechange.gov.au/renewabletarget.

The aim of the renewable energy target is to increase the production of renewable energy. Under the target, all electricity retailers and wholesale buyers have a legal liability to contribute towards the generation of additional renewable energy. They are called "liable parties", and meet their legal obligation by acquiring Renewable Energy Certificates (RECs). Each REC represents on MWh of eligible renewable energy.[336]

The expanded measure will be phased out between 2020 and 2030 as emissions trading matures and prices become sufficient to ensure that an MRET is no longer required to drive deployment of renewable generation technologies.

The *National Greenhouse and Energy Reporting Act 2007* establishes a single, national system for reporting greenhouse gas emissions, abatement actions, and energy consumption and production by corporations from 1 July 2008.[337]

Australia has a National Carbon Accounting System that accounts for greenhouse gas (carbon dioxide based) emissions from land. It accounts for both greenhouse gas emissions and removals (or sinks).

D.4.4.2 Emissions Trading Scheme

As part of the framework to address climate change, the government is establishing an ETS. The purpose of the ETS is to mitigate climate change by placing a limit on rights to emit greenhouse gases. The limit is to be reduced over time to a level that prevents any net accumulation of greenhouse gases in the atmosphere.

This constraint is imposed by the government creating permits which allow the holder to emit a set amount of greenhouse gases. The government then requires the emitters to hold these permits in order to emit greenhouse gases to the atmosphere. The permit is a tradeable instrument.

The government has indicated that the ETS must be a "cap and trade" scheme, in which total emissions are "capped". Permits are then allocated up to the cap. These permits are then able to be traded and the market will find the most economical way to meet any necessary reductions in greenhouse gases.

Emissions Trading Scheme Discussion Paper – March 2008

In March 2008, Professor Garnaut published an ETS Discussion Paper. It provides a framework to help Governments consider how to develop and deliver an effective Australian ETS.[338]

---

[336] Australian Government, Office of the Renewable Energy Regulator, Fact Sheet – Mandatory Renewable Energy Target Overview, February 2008, p.2. Available: http://www.orer.gov.au/publications/mret-overview.html.

[337] *The National Greenhouse and Energy Reporting Act* 2007. Available: http://www.climatechange.gov.au/reporting/legislation/index.html.

The Discussion Paper proposes principles and design features. These included: how to set an emissions limit and vary it over time to align with international agreements; how to allocate permits; what the breadth of the Scheme from the outset should be; and how appropriate an interim support for trade-exposed, emissions-intensive industries would be.

D.4.5 Climate Change Adaptation Strategies

There were a number of greenhouse gas abatement programs initiated by the federal government. These include: improving the efficiency of generation processes, providing funding for the uptake of small scale low-emission technologies, funding for the reduction of coal mine methane and devising a national framework for Australian businesses to report on greenhouse gas emissions.

Energy efficiency initiatives have also been applied to households and communities in relation to appliances and fittings, buildings and houses, encouraging eco-friendly transport options, rebates for solar hot water systems, along with climate education activities.

The government has devised a marketing regime whereby businesses can market their products using a "greenhouse friendly" logo to demonstrate to consumers that their products and services are greenhouse neutral.

There were mitigation and adaptation measures that were the responsibility of government including: local greenhouse action, energy efficiency in government operations, solar cities initiatives.

[338] Garnaut, Emissions Trading Scheme Discussion Paper, Garnaut Climate Change Review, March 2008, p.5. Available at: www.garnautreview.org.au.

D.5 Proposed NEM-wide options addressing dis-orderly bidding

As discussed throughout this Final Report, while the evidence indicated that the level of congestion had not been significant in the past, the emerging climate change agenda is likely to impact on the prevalence and materiality of congestion in the future.

While these options would not be proportional responses to the past level of congestion in the NEM, there may be scope in the future to consider options proposed by stakeholders during the course of this Review that looked to address the problems arising from congestion. While some stakeholders proposed options that would require substantial changes to the wholesale pricing and settlement arrangements (e.g. the LATIN Group's full CSP/CSC proposal), other stakeholders proposed more moderate solutions to the dis-orderly bidding problem. The dis-orderly bidding problem is a congestion-related policy challenge arising from the NEM's regional pricing design.

In this light, we present a summary of these proposals put forward in submissions to the Draft Report. We provide a description of the options, identify their characteristics, and present the proponents' reasoning as to why they consider the options would benefit the market.

The views expressed below are the proponents. We do not provide any commentary on or support for any of the proposals.

Before stepping through the various options, in February 2008, we published a framework paper by Gregan and Read on congestion pricing options for the NEM.[339] This paper set out a generic framework for describing different ways in which network congestion might be reflected in the wholesale pricing and settlement arrangements. All the options presented below can be characterised using that framework.

D.5.1 "Congestion management scheme (without allocating rights)" – group proposal

A group of generators[340] proposed this scheme late in this Review process.[341] They proposed the scheme as a means of addressing the distorted bidding incentives that the existing settlement process create in the presence of congestion. They consider this distortion is likely to increase with the rapid introduction of significant intermittent generation.

The following sections set out how the proposal is described and motivated by the proponents.

---

339 Gregan and Read, Congestion Pricing Option for the Australian National Electricity Market: Overview, February 2008.

340 The group includes: TRUenergy, International Power, Flinders Power, AGL, and LYMMCO.

341 TRUenergy, International Power, Flinders Power, AGL, and LYMMCO, Draft Report supplementary submission, Congestion Management Review, 4 April 2008.

D.5.1.1 Proposal objective

The principle objective of this proposal is to provide incentives to generators to bid efficiently by replacing the existing right to settle at the RRN with an alternative right. This has the secondary effect of eliminating the need for market intervention (e.g. clamping) while promoting inter-regional trade. The proposal works within the existing regional market design.

D.5.1.2 Proposal description

The proposal would apply universally to all binding constraints that contain generator terms. There are no prior allocation of rights. Instead, the alternative right to settlement is determined in real time has two components: the first is a share of the capability of the constraint (settlement adjustments sum to zero); and the second is a shared pro-rata based on presented capacity. The adjustment process at settlement is in three steps: the first includes existing regional settlement. The second two steps occur only if there is a binding constraint with a generator term.

The second step effectively brings the total settlement to the “local price”.[342] This removes the “dis-orderly bidding” incentive. The third step effectively brings total settlement to a point such that all generators receive a pro-rata “right” to RRN settlement, plus variations at the local price.[343]

For generators, the shared pro-rata is on the basis of bids; for interconnectors is it on the basis of other limits.

D.5.1.3 Proposal characteristics

According to the proponents, the proposal allows the current dispatch process to work with more efficient bidding incentives; the adjustments are in settlement only. It treats interconnectors and generators equally. This restores inter-regional hedging capacity as well as eliminating the need for NEMMCO intervention in dispatch (e.g. clamping).

The proposal is aimed at improving operational efficiency. It does not distinguish between new generators and existing ones. A new generator can locate in a congested area and will receive an equal share of congestion to existing generators. It therefore does not improve investment locational signals, nor the level of congestion. It does address the symptoms of congestion.

---

[342] This step is identical to CRA’s constraint support pricing (CSP).

[343] This step is equivalent to CRA’s constraint support contract (CSC).

D.5.1.4 Proposed benefits

The group of generators cite a number of benefits from the proposal. According to these generators, this proposal would:

- eliminate the incentives for "dis-orderly bidding", allowing efficient operation of a regional market;
- have a low implementation cost, requiring only the development of an additional settlement process;
- fund negative settlement residues arising from inter-regional counter-price flows, thereby eliminating the need for physical intervention in dispatch to manage negative settlement residue accumulation;
- not give priority in dispatch to any participant or groups of participants;
- reduce participant incentives to distort unit dispatch targets, such as ramp rates or "inflexibility";
- not deprive participants of an existing right without equivalent compensation;
- not require an auction or ex-ante allocation of "rights", thereby providing more predictable access to the RRN and improving hedging, both intra and inter-regionally; and
- assist the AER in measuring congestion as it reveals the true constraint price.

D.5.1.5 More detailed design issues

There are several design issues identified by the group. These include:

- the time interval for the settlement process;
- the derivation of relevant energy quantities;
- the definition of availability for interconnectors;
- a pure constrained-on case; and
- a "mixed constraint" case, where a constraint simultaneously constrains-on and –off generators and/or interconnectors.

These issues are discussed in more detail below.

Time interval for the settlement process

The processes under the proposal are purely "mechanical" and are based on dispatch data. It would therefore be convenient to operate the proposal on a dispatch interval basis. This is consistent with the existing settlement arrangements for market ancillary services. The existing 5-minute/30-minute anomaly[344] remains but the proposal would not make it worse.

Derivation of relevant energy quantities

Spot prices are calculated as a price at generator terminals, but are settled to the sent-out basis, after the internal generator use is deducted. This existing issue in settlement remains in this scheme, but is not made worse. Steps 2 and 3 of the proposal must both use either generated or sent-out energy.

The group recommends the use of sent-out energy. This would be derived from: (1) revenue metered sent out energy for a trading interval (30-minute basis); (2) generated energy for a dispatch interval (5-minute basis) based on beginning and end generated values (as used in dispatch); and (3) the relationship between generated and sent-out energy for each unit for each trading interval.

Using this definition of sent out energy would require a consequential minor change to the definition of RRN share to include this relationship between generated and sent out energy.

Definition of availability for interconnectors

Under the proposal, there needs to be a definition of availability. For a generator, the availability defines the maximum use of the constrained link that the generator could make, if it out-competed its competitors.

Interconnectors are simultaneously subject to several constraints. Each represents a limit on a different network component. The group proposes that interconnector availability be represented using the most restrictive non-binding constraint. This defines the capability of the interconnector if it out-competed its rival generators and/or interconnectors.

NEMMCO already has a tool to evaluate this.

Pure constrained-on case

Under the proposal, the incentive for a constrained-on generator to withdraw capacity remains. To resolve this issue, the proposal would incorporate a compensation payment to the constrained-on generator. As a financially-balanced process, i.e. a process equally offsets increased settlement payments to some generators using funds from other generators, this proposal cannot directly supply a constrained-on payment. Instead, the group proposes that under this case, steps 2 and 3 of the adjustment are omitted.

344 Dispatch is on a 5-minute basis while settlement is on a 30-minute basis. Flows on interconnectors can sometimes change direction within a 30-minute period. When this happens, there may be a disparity between the 5-minute dispatch and 30-minute settlement outcomes.

Cases with "mixed constraints"

There are generators that can facilitate more network capacity for other generators or an interconnector. These generators are known as "positive gatekeepers". The option proposed defines a settlement process to reward the positive gatekeeper based on benefits conferred, and therefore, provides incentives for more efficient dispatch.

To provide such incentives, the constrained-on units would have a zero adjustment in Step 3. This leads to these units having net revenue at their local price. To fund this adjustment, the constrained-off units' adjustment would only share the network capability that would have been available without the positive gatekeeper, not the larger capability now enabled. It is important to note that the local price received by the positive gatekeeper is limited by the economic benefit in dispatch.

D.5.2 "Mechanism with registered capacity non-firm financial rights" – Hydro Tasmania proposal

Hydro Tasmania proposed a mechanism with non firm financial rights as a way of promoting incentives for more economically efficient dispatch.[345]

D.5.2.1 Proposal objective

The proposal's aim is to limit the dispatch volume for each constrained generator is guaranteed the RRP. This will provide incentives, at the margin, for generators to bid in an efficient manner. The proponent contends that it would have low costs of implementation.

D.5.2.2 Proposal description

For dispatch up to a given amount or "congestion residue" holding, a generator would receive the RRP. For any dispatched volume above the residue holding, the generator would receive the local nodal price. This would be the case independent of whether the residues were allocated or auctioned.

This proposal would apply to each constraint equation individually, with zero-sum[346] post dispatch settlement adjustments[347]. Because the adjustments to settlement are post-dispatch, the proposal does not directly impact on operational timeframes.

---

345 Hydro Tasmania, Submission to Draft Report, Congestion Management Review, 3 December 2008, pp.7-8.

346 This is the case if there are no uplift payments to constrained-on generators.

347 There is a potential 5-minute/30-minute issue, but with 5 minute market metering on all dispatchable variables, this can be resolved.

Hydro Tasmania proposes to allocate non-firm financial rights on the basis of registered capacity at the proposal's inception. Participants are free to negotiate with TNSPs to fund transmission augmentations over and above what is justified under the Regulatory Test, and would receive additional financial rights for the augmented amount.

The proposal is an automatic process. It does not rely on selecting a set of significant constraints or require continuous monitoring and regulatory action. This proposal provides a set of future processes to deal with congestion as it emerges and recedes

There is currently an allocation of "congestion residues" in the NEM today. A generator receive an allocation of congestion residues for a particular constraint equation if they are located in a "remote local" location but not if they are located in an adjacent NEM region.

An allocation based on registered capacity (or availability factor) would mean new generators would not automatically receive access to congestion residues. This means new investors would need to account for transmission costs as part of a project, as Hydro Tasmania stated as economically efficient. New generators would have options to: accept occasionally constrained output; contribute to augment the network, receiving a total congestion residue equal to the upgraded capacity; or accept a lower price than existing generators, but "winning" a share of network access.

The proposal does not attempt to firm up allocations from external funding. This creates a risk at the margins that net settlement may be at a generator's offer price.

As congestion increases, Hydro Tasmania considers the impact of the proposed measures will also increase. This proposal would provide certainty to the market as to what the response would be in the event that congestion does emerge, either as a consequence of new investment or through other events, like NEMMCO applying temporary network constraints to manage power system security.

D.5.2.3 Proposed benefits

According to the proponent, this option:

- will deliver investment certainty in relation to transmission access; and
- will help manage trading risks that can arise even if a constraint equation binds on rare occasions only.[348]

[348] This is because, the impact on the willingness to enter the contract market is based on the "perceived risk that it may bind" at some time in the future. In addition, the dispatch risk currently managed by dis-orderly bidding, like -$1 000/MW, can be a significant barrier to inter-regional trade. There is always a trade-off between dispatch and basis risk.

D.5.3 "Real time settlement adjustment mechanism" - Babcock and Brown Power proposal

In its submission to the Draft Report, Babcock and Brown put forward a proposal outline to improve dispatch efficiency.

D.5.3.1 Proposal objective

Babcock and Brown Power proposed that market mechanisms should be explored to improve the real time management of constrained power flows using real time adjustment to settlements.[349]

D.5.3.2 Proposal description

The proposal suggested a settlement adjustment for parties in a binding constraint equation based on the constraint equation coefficients and generation presented to the market. Babcock and Brown considered that unlike the current "tie break" arrangements, this approach would reduce the output of generators proportionally to their contribution to the binding constraint.

D.5.3.3 Proposed benefits

According to the proponents, this scheme would:

- create a more predictable and efficient dispatch outcome;
- remove distorted bidding incentives;
- avoid introducing additional complexity through locational pricing;
- allow for a more accurate calculation of the true cost of congestion; and
- involve minimal implementation costs.

[349] Babcock and Brown Power, Draft Report submission, Congestion Management Review, 12 March 2008, p.3.

This page has been intentionally left blank

E Additional background information

E.1 Introduction

This appendix contains supplementary information on a variety of congestion-related topics including:

- E.2 – information on the types of constraints used in the NEM;
- E.3 – a review of CRA work on constraint management ;
- E.4 – the history of Network Support and Control Services; and
- E.5 – explanation of Positive Flow Clamping options.

E.2 Types of constraints

This section provides additional details on the three broad types of constraint used in the dispatch process to represent the underlying physical network. It explains the effects of each constraint type on regional reference prices. It also indicates the prevalence of each constraint type (based on an analysis of a single dispatch interval on a working day afternoon in July 2007, under "system normal" conditions).

The three broad types of constraint are:

1. *pure intra-regional constraints* (pure intra-regional limits);

2. *pure inter-regional constraints* (pure interconnector limits); and

3. *trans-regional constraints*, which may involve:

   (a) a single interconnector and local generation units (i.e. hybrid constraint);

   (b) multiple interconnectors and local generation units; or

   (c) interactions between two or more interconnectors, without any local generation involved.[350]

E.2.1 Pure intra-regional constraints

A pure intra-regional constraint restricts the flow of power through a constrained network element within a region, but is not affected by power flows from other regions; that is, the physical effects of the constraint are limited to a single region. If a binding pure intra-regional constraint affects power transfers to and from the RRN, then the RRP will reflect the impact of the constraint binding. If a binding pure intra-regional constraint does *not* affect power transfers to and from the RRN, then the RRP will *not* be affected in any way. These two cases are illustrated below. All examples assume that there are no network losses and that each generator offers all its capacity at the offer price indicated.

E.2.1.1 Case 1. A pure intra-regional constraint that affects the RRP

In this case, a pure intra-regional constraint binds in such a way that power flows to the RRN are affected. In order to balance supply with demand at the reference node, either additional energy is required or demand must be reduced. The incremental cost of procuring additional supplies of energy at the RRN as a direct result of the constraint binding is the congestion cost of the constraint. This congestion cost is reflected in the RRP.

---

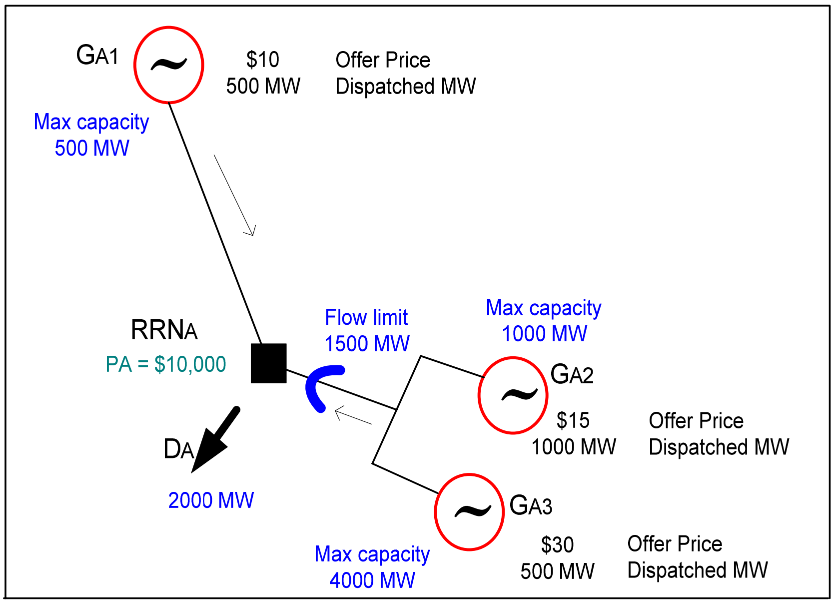
[350] For further discussion of trans-regional constraints and their pricing impacts, see the CRA report, *NEM Interconnector Congestion: Dealing with Interconnector Interactions*, Report to NEMMCO, Wellington, 2003. Available at http://www.mce.gov.au/assets/documents/mceinternet/InterconnectorInteractions20041123171938%2Epdf.

In the example in Figure E.1, there is no way of increasing generation to meet a 1 MW increase in load at the RRN because G_{A1} is at maximum output and the 1 500 MW transmission limit restricts additional output from G_{A3}. Therefore, in the absence of any demand-side bids, the marginal price at the RRN is set by VoLL, $10 000/MWh. It can be shown that the marginal economic cost of the congestion equals $9 970/MWh.

If this flow limit persisted over time, then the congestion costs implicit in the RRP could provide incentives for economically efficient investments to:

- upgrade the transmission line from G_{A3} and G_{A2} to the RRN;
- increase the amount of generation capacity located on the other side of the constraint, which has unrestricted access to the RRP; and
- reduce demand at the RRN through demand-side management.

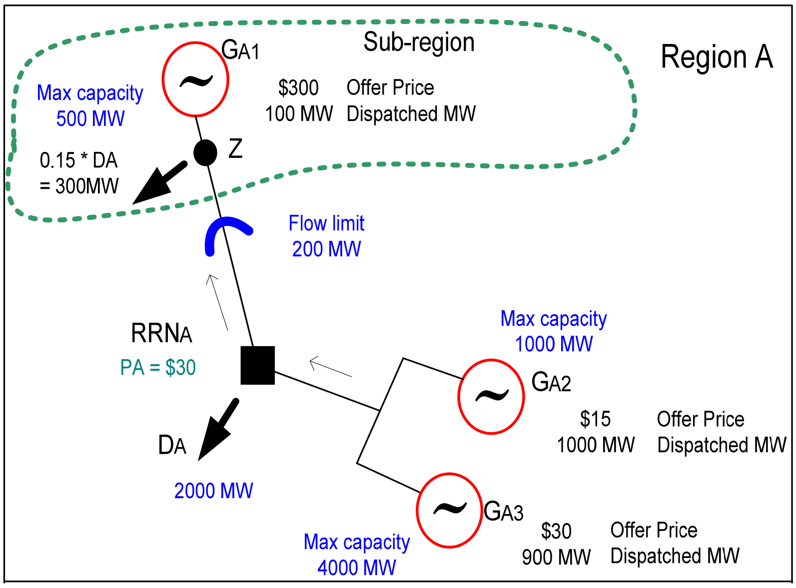
Figure E.1 Pure intra-regional constraint that affects the RRP



E.2.1.2 Case 2. A pure intra-regional constraint with no impact on RRP

In this case, a pure binding intra-regional constraint has no effect on the RRP. In the example in Figure E.2, total demand at the RRN is 2 000 MW, but 15% of this load (i.e. 300 MW) occurs physically in the sub-region containing node Z. Incremental demand at the RRN can be met by G_{A3}, at a price of $30, which sets the RRP. At that price, G_{A1} would not expect to be dispatched based on its offer price of $300. However, in order to meet the 300 MW demand at node Z, generator G_{A1} will have to be constrained-on to meet the 100 MW of the sub-regional load at Z that cannot be met because the 200 MW flow limit is binding.[351] Under the Rules, generator G_{A1} would be paid the $30/MWh reference price for all its output because it is constrained-on generation that has no effect on the ability to balance supply and demand at the RRN.

Figure E.2 Pure intra-regional constraint with no impact on RRP



The Rules also state that if a generator is initially unavailable but is directed by NEMMCO to start generating, it may apply for compensation payments when the RRP is below the price at which it is prepared to offer its capacity.

These pricing arrangements can provide incentives for:

- G_{A1} to declare itself unavailable, so that it can be compensated at a higher price than the reference price;[352] and
- the local TNSP and G_{A1} to enter into a NSA.

E.2.2 Pure inter-regional constraints

A pure inter-regional constraint is one in which the ability to transfer power between RRNs is affected not by power flows through a constrained element within a region

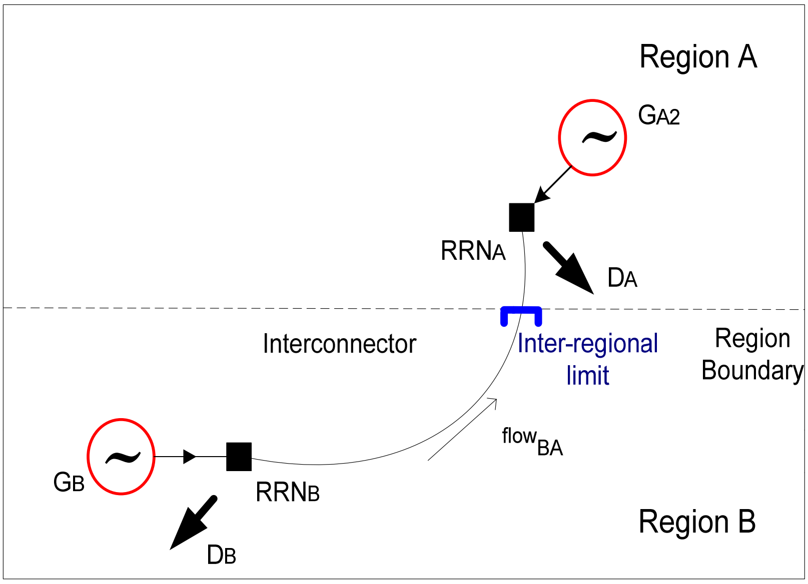
[351] Although all load is notionally treated as being at the RRN, in reality load occurs at different locations of the network. TNSPs and NEMMCO are both required to meet loads across the physical transmission network, not just at RRNs.

[352] This might occur if: a) G_{A1} has SRMC that are substantially above the prevailing spot price; b) G_{A1} is seeking to exercise its localised market power; or c) GA1 wishes to capture underlying economic rents that are not explicit because of the NEM's regional pricing structure.

but by the (security-constrained) physical capabilities of the interconnector itself (see Figure E.3 below).

Pure inter-regional constraints relate to pure interconnector limits (PILs). A PIL represents the sum of bounds on the actual physical lines joining adjacent regions, which may imply binding limits on the corresponding notional interconnector.

Figure E.3 Pure inter-regional constraint



Under the NEM's pricing rules, pure inter-regional constraints will be fully reflected in the price of energy at the boundary between two regions.

When there is a pure inter-regional constraint it is usually necessary for additional generation in the importing region to be dispatched to meet load in that region, even though it may have a higher offer price than that of generation located in the exporting region. Under these circumstances the price in the importing region will usually rise, with all customers in the importing region paying—and generators in the importing region receiving—the higher price, while customers and generators in the exporting region face a relatively lower price.

E.2.3 Trans-regional constraints

Trans-regional constraints involve both intra-regional generation and inter-regional flow terms. Trans-regional constraints are typically of non-radial form.

Most network limits, when expressed correctly in a fully-optimised formulation, produce "trans-regional" constraints.

There are three classes of trans-regional constraint, each of which has different characteristics and implications for pricing and the financial settlement positions of market participants:

1. a single interconnector and local generation units (i.e. hybrid constraint);

2. multiple interconnectors and local generation units; and

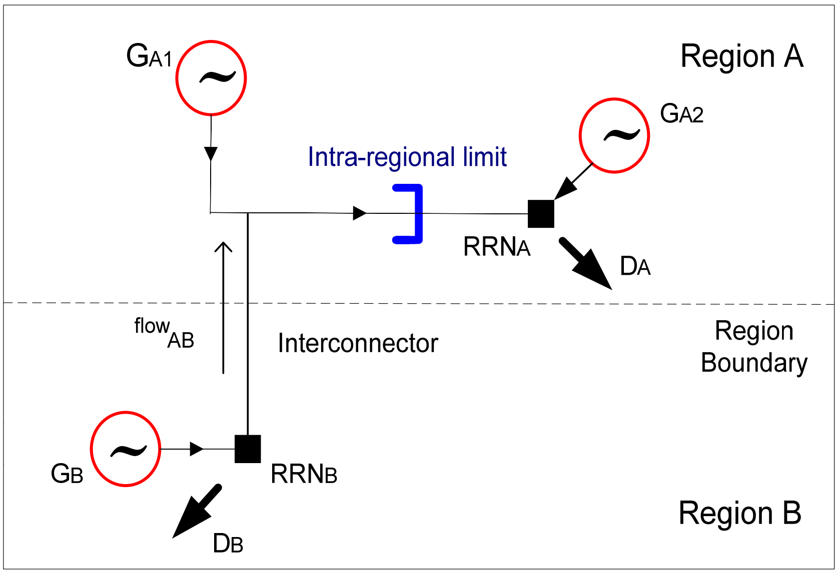
3. interactions between two or more interconnectors.

E.2.3.1 Single interconnector and local generation units (hybrid constraint)

We refer to a constraint involving a single interconnector and generation units within a region as a "hybrid" constraint.

In a hybrid constraint, power-flows through the constrained network element are affected by a combination of: flows along a single interconnector and flows through constrained network elements within a region. This is illustrated in Figure E.4, where there is a network limit between generator G_{A1} and the RRN in Region A (RRN_A). This limit affects the ability of both G_{A1} and the interconnector to supply power through the constrained element of the network. In this case, when the constraint binds, additional demand at RRN_A will be met by output from generator G_{A2}, whose ability to deliver power to the RRN is unaffected by the constraint. Given that G_{A2} will be the marginal supplier at the RRN, under the NEM Rules it will set the price at RRN_A. The price at the RRN in Region B (RRN_B) could also be affected by the constraint if flows on the interconnector change the marginal cost of balancing supply and demand at RRN_B.

Figure E.4 Hybrid constraint, involving a single interconnector and local generation units



The relative locations of the point of congestion, the RRN, generation, and the interconnector, all play a role in determining the extent to which the congestion affects the RRP in the region with the constraint and in the regions linked by the interconnector.

E.2.3.2 Multiple interconnectors and local generation units

In a trans-regional constraint involving multiple interconnectors and local generation units, power-flows through the constrained network element are affected by a combination of: flows along more than one interconnector and flows through constrained network elements within a region. These types of constraints typically involve either:

- a physical transmission loop wholly within one region, to which are connected local generators and interconnectors; or
- a physical transmission loop that spans two or more regions.[353]

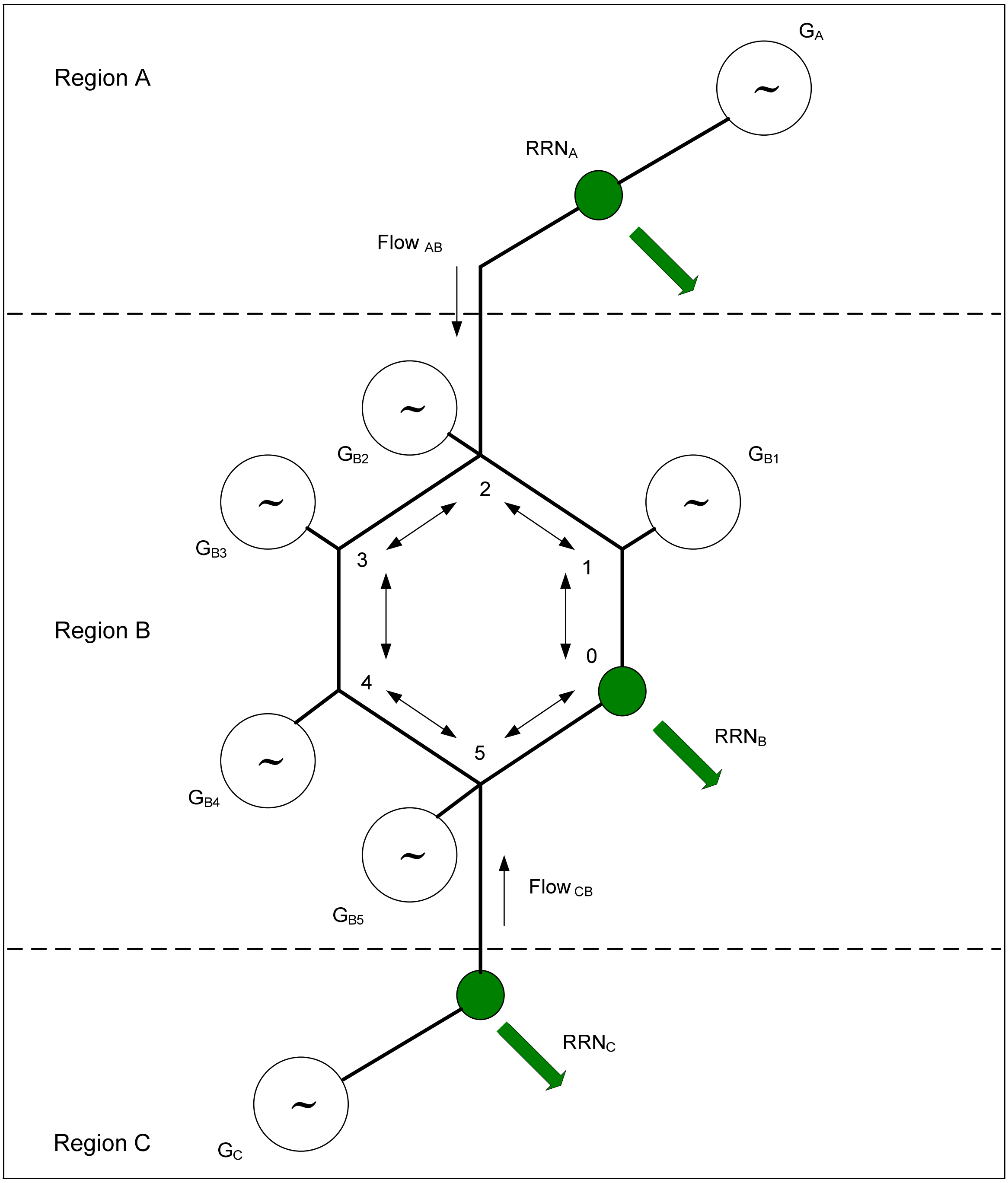
Figure E.5 provides an example of this type of constraint, where the loop is wholly within one region. In this example it is assumed that the network is unconstrained, that demand in Region B is high, and that the least-cost security-constrained dispatch results in:

353 For example, the transmission loop spanning the Victoria, NSW and Snowy regions, prior to the abolition of the Snowy region. This Snowy loop and its pricing effects are discussed in Appendix A of AEMC 2006, *Management of negative settlement residues in the Snowy region*, Final Rule Determination, 14 September 2006, Sydney, pp. A2-A4.

- Region B importing power from Regions A and C; and
- the dispatch of generation in Region B to meet Region B demand.

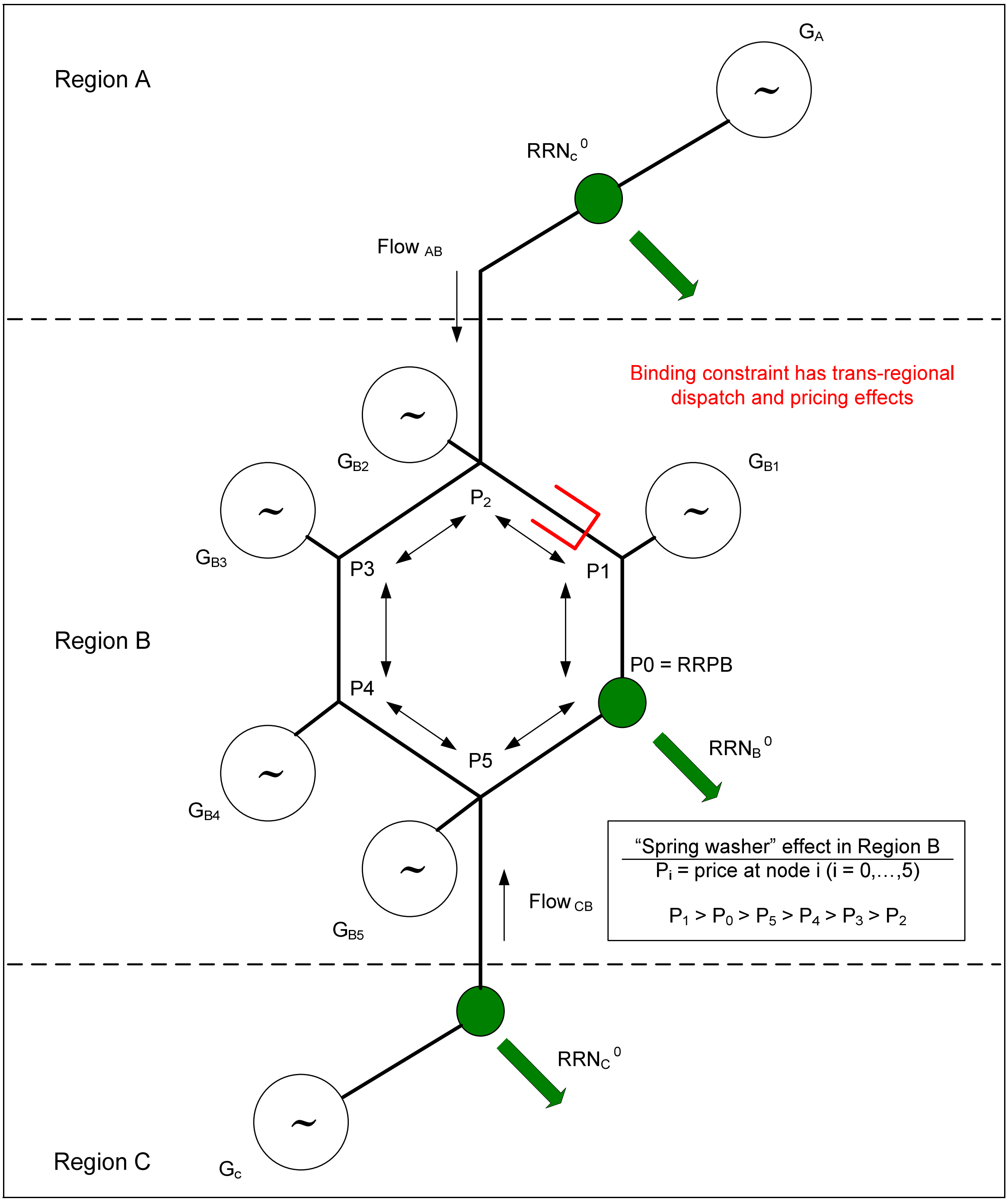
In this case, power flows around the loop within Region B towards the Region B RRN (RRN_B or node 0). The nature of the flow depends on the relative electrical impedance of the two alternate routes around the loop, measured at each of the five injection points 1 to 5, where generators (G_{B1} to G_{B5}) or interconnectors join the loop.

Figure E.5 Multiple interconnectors and local generation units, uncongested



Now assume that a constraint binds within Region B on the live connection G_{B2} to G_{B1} — i.e. nodes 2 and 1 (see Figure E.6). This binding constraint affects the ability to deliver power to RRN_B (node 0).

Figure E.6 Multiple interconnectors and local generation units, congested



The binding constraint in Region B between nodes 2 and 1 has the following effects:

1. A spring washer pricing effect arises within Region B, in which there is a pattern of nodal prices whereby the highest price occurs at the point where G_{B1} connects to the loop and the lowest price occurs where G_{B2} connects to the loop, with nodal prices falling in a clockwise manner. In this situation all the generators in Region B are constrained-on or -off relative to RRP_B, to some degree.

2. Generation and interconnector flow that most adds to congestion has to be backed off (i.e. G_{B2} and $flow_{AB}$).

3. Generation that most relieves the binding constraint has to be increased (i.e. G_{B1});

4. Generation and interconnector flow at all other points of the network will have to be adjusted so that the constraint is not violated (i.e. G_{B3}, G_{B4}, G_{B5}, $flow_{CB}$). The adjustments in the volume of power injections at these locations will be related to the marginal impact that the change has on power flowing through the constrained network element.

5. The mathematical coefficients representing the generator and interconnector flow variables are indicative of the impact that a marginal change in the value of the variable will have in relieving the binding constraint.

6. The value of changes in interconnector flows is captured in the NEM's pricing and settlement Rules, and accrues to the inter-regional settlement residue funds for $flow_{AB}$ and $flow_{CB}$.

7. The value of locationally adjusting generation within Region B to relieve the constraint (or not violate it) is not reflected in the settlement prices paid to generators within Region B. Instead, they are settled at RRP_B. However, the dispatched generation *volumes* of generators G_{B1} to G_{B5} do reflect the value that power injections at each location (based on offers) have in relieving the constraint. This can result in generators being constrained-on or constrained-off, relative to the settlement price, RRP_B. When generators are constrained-on or -off in Region B, they face dispatch risk and have incentives to alter their offers to mitigate that dispatch risk by aligning their dispatch volumes with the volumes they are willing to supply at RRP_B. This can result in "dis-orderly bidding", which can potentially have a negative impact on the economic efficiency of dispatch, and increase uncertainty about the level of interconnector flows and inter-regional price differences. That is, "dis-orderly bidding" can reduce the firmness of the inter-regional settlement residues (IRSRs), thereby diminishing the usefulness of IRSR units as a means of managing inter-regional trading risks.

8. Note that this single binding constraint within Region B affects dispatch, pricing and settlements across the entire market, as follows:

   (a) With local demand unchanged in Region A, and generator offers unchanged, the price in Region A will fall—both relative to RRP_B and in absolute terms—because the effective demand in Region A (i.e. load in Region A plus net exports) has fallen relative to the supply curve in Region A.

   (b) Similarly, with local demand in Region C unchanged, the price in Region C will rise towards that in Region B, as more costly generation in Region C is dispatched to meet the higher level of net exports from C to B.

As before, the relative locations of the point of congestion, the RRN, generation, and the interconnectors, all play a role in determining the extent to which the congestion affects the RRP in the region with the constraint and in the regions linked by the interconnectors.

For further discussion of trans-regional constraints and their pricing impacts, see the CRA report, *NEM Interconnector Congestion: Dealing with Interconnector Interactions.*[354]

E.2.3.3 Interactions between two or more interconnectors, and that do not involve generation

Interactions between two or more interconnectors, that do not involve generation, are very rare (see section E.2.4 below). However, there are a few examples that occur in the NEM, which primarily relate to stability constraints.

In these cases where there is no generation directly represented in the constraint, flows on one interconnector are affected by flows on at least one other interconnector—i.e. there is interconnector interaction. These pure interconnector interactions can take several forms:

- requiring greater flow on one interconnector in order for flow on the other to increase;
- requiring counter-price flow on one interconnector to support flows on other interconnectors in order to minimise the total costs of dispatch; and
- requiring stability constraints designed to keep the six regions of the NEM electrically intact in the event of a contingency that creates a transient stability or voltage stability issue.

The most common type of interacting interconnector constraints also involve generation (see section E.2.4 below). These are discussed in section E.2.3.2.

E.2.4 Incidence of constraint types

The incidence of the three broad types of constraint provides an indication of how likely they are to affect the setting of RRPs in any dispatch interval. A snapshot view of the incidence of constraint types can be gauged by examining the constraints that were invoked during a particular dispatch interval.

NEMMCO randomly sampled a dispatch interval in the mid to late afternoon of 17 July 2007, and classified the constraints that were invoked. There were only a few prior outages of transmission plant on that day, so the dispatch interval seems to be representative of system normal conditions.

---

[354] CRA(2003b) *Dealing with NEM Interconnector Congestion: A Conceptual Framework*. Released by the National Electricity Market Management Company of Australia, March 2003.
CRA(2004c) *NEM Interconnector Congestion: Dealing with Interconnector Interactions*. Released by the National Electricity Market Management Company of Australia, October 2004
http://www.mce.gov.au/assets/documents/mceinternet/InterconnectorInteractions20041123171938%2Epdf

Here are the findings based on an analysis of that single dispatch interval:

1. At any point in time under system normal conditions, it can be expected that up to about 400 constraints will be invoked and active in the dispatch process.

2. Of these 400, around 20% (i.e. 80) are associated with FCAS requirements, and half of these FCAS constraints are for Tasmania.

3. Around 75% (i.e. 300) of the total constraints are trans-regional constraints that involve at least one interconnector.

4. Of the 300 non-FCAS constraints that involve interconnectors, about 230 of these also involve generating units. That is, around 77% of the non-FCAS constraints are trans-regional constraints that involve either:

   (a) a single interconnector and local generation units (i.e. hybrid constraint); or

   (b) multiple interconnectors and local generation units.

5. To put it another way, around 58% of the total of 400 constraints (i.e. 230/400) invoked in the dispatch interval, are trans-regional constraints involving generation interacting with one or more interconnectors.

6. Around 31% (i.e. 120) of all constraints are trans-regional constraints involving more than one interconnector.

7. Of the 120 trans-regional constraints involving multiple interconnectors, about half have two interconnector terms. However, there are six trans-regional constraint equations that include all five interconnectors (including Basslink) in them. These six constraints most likely relate to stability constraints.

8. Of these 120 constraints, about 55% have different signs on the interconnectors and 45% have the same sign. This indicates an interaction between the interconnectors, which could include:

   (a) one interconnector supporting flows one or more other interconnectors;

   (b) one interconnector blocking flows one or more other interconnectors;

   (c) the minimisation of electrical losses on flows across two or more interconnectors; and

   (d) stability constraints designed to keep the NEM electrically intact in the event of a disturbance.

9. Only around 20 constraints (i.e. 5% of the 400 total, and 6.25% of the 320 non-FCAS constraints) were either:

(a) outage related;[355]

(b) pure intra-regional; or

(c) pure inter-regional.

The conclusion of this analysis is that, under system normal conditions, the majority of active transmission constraints in the NEM are trans-regional constraints, and that the bulk of these trans-regional constraints involve one or more interconnectors interacting with generation in a region.

355 There were around 12 network outages and restrictions that day, comprising: a) 1 constraint arising from one of the three Directlink cables being out of service; b) about 6 constraints to manage an outage on the Ballarat to Kerang 220 kV circuit; c) several constraints relating to the Armidale transformer, which restricted flows into the 132 kV system that parallels QNI; and d) a limit on power flows between Central Queensland and Southern Queensland.

E.3 Review of CRA work on constraint management

E.3.1 Introduction

This section reviews recommendations on constraint formulation and pricing made to the MCE by Charles River Associates (CRA) in 2004.[356] It also reviews the submissions made to the associated consultation, and CRA's responses to those submissions.

The AEMC is required, under clause 3.3 of the Congestion Management Review's Terms of Reference, to have regard to CRA's work on constraint management and to use the submissions to the associated consultation as the basis of our own review of constraint management.[357]

CRA presented its Consultation Report, containing draft recommendations on constraint management, to the MCE in September 2004. In response to this report, the MCE received a total of 24 submissions.[358] CRA then completed a Final Report for the MCE in April 2005, which the MCE published in 2007.[359] In the Final Report, CRA made the same recommendations as in the Consultation Report but clarified a number of matters in light of the submissions.

CRA's Consultation Report addressed the criteria for setting future boundaries for price regions, and advocated a staged approach to congestion management. It also looked at how the technical characteristics of the transmission network are represented in the constraint formulation process by NEMMCO. The key recommendations were as follows:

- Implicitly absorb within the energy market the costs of minor levels of congestion.
- Regularly publish information on existing and emerging congestion in the NEM.
- Introduce consistent constraint formulation throughout the NEM, as well as a practical measure to limit the scope for counter price flows between regions.
- Introduce an economic test in the criteria for assessing proposed changes to the regional structure.
- Establish a timeframe for conducting regional boundary reviews, announcing boundary changes and maintaining any new regional structure.

[356] Charles River Associates, Consultation Draft, *NEM – Transmission Region Boundary Structure*, September 2004.

[357] Ministerial Council on Energy, Congestion Management Review Terms of Reference, 5 October 2005, p.4.

[358] Organisations which made submissions are listed in F3.5. The submissions themselves are available from the MCE website: www.mce.gov.au

[359] Charles River Associates, Final Report, NEM - Transmission Region Boundary Structure, April 2005.

- Ensure consistency between the application of the Regulatory Test and region boundary reviews.

- Develop a contracting/pricing mechanism to deal with material congestion until the problem is addressed by investment or regional boundary change.

- Request market authorities to develop a program to implement a congestion management contracting and pricing regime, using the proposal for Constraint Support Pricing and Contracting as a starting point.

CRA's recommendations were based upon the view that transmission constraints, at least within regions, will not be prolific because transmission investment will occur in a timely manner, and that stability in the market environment promotes the certainty and predictability required to encourage suitably located generation investment. CRA concluded that full nodal pricing (and settlement) of both generation and load is not required. However, CRA did recommend that, given the regulatory framework for network investment, it would be beneficial to implement a form of targeted generator nodal pricing and settlements, which would be utilised to manage material congestion. Under this approach, according to CRA, pricing and settlement for loads would continue to be regional.

CRA's views and recommendations on constraint management and pricing fall into four topics:

- constraint formulation;

- responding to strategic bidding behaviour by generators;

- managing counter-price flows; and

- constraint contract and pricing mechanism.

By topic, this section reviews CRA's draft findings and recommendations, the responses from submissions, and CRA's rejoinders from its Final Report.

E.3.2 Constraint formulation

E.3.2.1 CRA draft report recommendations

CRA made the following recommendations as to how constraints should be formulated in the NEM for optimal dispatch:

- No change should be made to the existing dispatch objective, which is to optimise each dispatch run on the basis of the prices presented at the time.

- NEMMCO should adopt a consistent approach to constraint formulation and use a direct physical representation (either Option 4 or Option 5). CRA noted this is consistent with the market design principles in the Code that call for NEMMCO decision-making to be minimised.

- Options 4 and 5 each allow for variables to be fully optimised by the dispatch engine and will produce physically equivalent outcomes assuming the same physical network representation. Option 4 should be used if dispatch uses a regional model, and has varying constraints' orientations yielding prices corresponding to different regional RRNs. Option 5 should be used if dispatch uses a full network model[360].

- The issue of whether or not to apply Option 5 is not dependent upon the implementation of nodal pricing because dispatch and pricing arrangements can be decoupled. The choice between Option 4 and Option 5 should be based upon system security. NEMMCO should conduct a review if it believes a full network model (Option 5) is necessary in order to meet its obligations for system security.

- Constraint equations should be reviewed and updated on a regular basis.

- The shadow prices behind intra-regional constraints should be published.

E.3.2.2 Summary of submissions

There was overwhelming support for CRA's recommendation that NEMMCO adopt a consistent approach to constraint formulation using direct physical representation of the network.

Snowy Hydro agreed that dispatch and pricing can be decoupled, and commented that the dispatch model must represent the underlying electrical network in order to correctly manage loading.

Most of the submissions supported the publication of shadow nodal prices. Only the Queensland Generators[361] argued against it, commenting that the information would not mean much because of the bidding wars between generators and because bidding is driven by dispatch rather than revenue.

Option 4 versus Option 5

Regarding the choice between Option 4 and Option 5, most submissions were fairly neutral, while some argued in favour of Option 4.

The Queensland Generators group considered Option 4 best because it provides optimal dispatch of plant and secure utilisation of the full transmission capacity. It thought CRA overstated the possible benefits for system security from applying Option 5 (full network model), and argued that the approximation of fixed loss factors under Option 4 is not a problem when many constraints use actual measured flows in feedback-type constraints. It also argued against other options raised

---

[360] A full network model directly represents the electrical characteristics of each and every physical transmission element, the limits applying to that element, as well as system security constraints that apply to more than one element.

[361] The joint submission from the "Queensland Generators" included CS Energy, Enertrade, InterGen, Stanwell and Tarong Energy.

previously, because such options give a particular category of generators priority over others by removing them from the left-hand side of the constraint and because this allocation of priority can be arbitrary.

Delta Electricity supported the adoption of Option 4 constraint formulation but added that it can be enhanced through the equalisation of constraint equation coefficients. It recommended that near-identical constraint equations be equalised in order to prevent inappropriate and perverse constraints.

"The Group"[362] thought a full network model would not be required if Option 4 were supported by an appropriate counter-flow management regime. It also supported Delta's equalisation proposal.

Energy Retailers Association of Australia (ERAA) said it would support the implementation of the full network model if NEMMCO could demonstrate that the cost of implementation would be outweighed by the benefits.

Many submissions supported the recommendation for NEMMCO to consult on whether Option 5 is required for system security. Both the National Generators Forum (NGF) and Southern Hydro thought the consultation should evaluate other costs and benefits besides system security. The Group argued against the consultation, noting that Option 4 was in part proposed by NEMMCO for system security reasons.

E.3.2.3 CRA Final Report: further comments

CRA maintained its position that a consistent and direct physical representation of the network (either Option 4 or 5) would be best because it would allow decisions on physical representation to be decoupled from the design of the pricing regime.

E.3.3 Responding to strategic bidding behaviour by generators

E.3.3.1 CRA draft report recommendations

Having noted that addressing adverse bidding behaviour is required for congestion management and that, whether Option 4 or 5 constraint formulations are used, some generators may have incentives to bid below their short-run marginal cost of production (SRMC) where intra-regional constraints bind, CRA made the following recommendations:

- The form of the general constraint equation should not be modified to prevent or deter distorted bidding. Rather, such behaviour should be referred to and dealt with by the relevant (competition) authorities.

---

[362] "The Group" consists of AGL, Delta Electricity, Loy Yang Marketing Management Company, Macquarie Generation, Stanwell Corporation, Yallourn Energy, Powerlink and Transgrid. Their submission was prepared by Frontier Economics.

- Changes to constraint formulation or to region boundary structure may only solve some bidding behaviour but could create new adverse bidding. This is because network congestion will always create pockets of localised market power.

E.3.3.2 Summary of submissions

Some of the submissions questioned CRA's view that strategic bidding behaviour is anti-competitive. Enertrade considered it grossly inaccurate to characterise as inappropriate those bidding practices which respond to the current rules, and said there is no evidence to support CRA's view that such behaviour is an abuse of market power. TXU Energy thought the additional cost of the increased risk burden caused by uncertainty of dispatch needs also to be modelled to understand the current dispatch inefficiency, and noted that NEMMCO's constraint equations are not designed to deal with the allocation of transmission capacity. The increased risk burden, in turn, would lead to strategic behaviour which would result in the withdrawing of capacity from the contract market.

Other submissions questioned the value of referring these matters to competition authorities. The Group considered that referring market power issues to the ACCC would be ineffective. It noted that the ACCC's approval of the National Electricity Code Administrator's (NECA) rebidding Code changes did not follow directly from its enforcement of the part IV competition provisions of the Trade Practices Act, but rather from the Code requirement that virtually all Code changes are to be authorised by the ACCC. Therefore, simply 'referring dis-orderly bidding' to the ACCC would be unlikely to result in any control over this behaviour unless accompanied by a relevant Code change proposal. The Group argued that even in these circumstances, as with the rebidding Code changes, the ACCC would probably be reluctant to intervene in participant bidding behaviour that did not involve an exercise of market power for a proscribed purpose or anti-competitive agreements. It added that if the good faith bidding provisions in clause 3.8.22A were applied in a way that seeks to prevent dis-orderly bidding—by, for example, proscribing certain negative bids—this would represent a major behavioural intervention in the market and could create a great deal of uncertainty and dispatch inefficiency.

E.3.3.3 CRA Final Report: further comments

CRA stood by its recommendation to refer concerns about inappropriate bidding behaviour to the relevant authorities, claiming that it is important to have a clear separation between market operations and responsibility for enforcing trade practice provisions. It noted that this sort of policy response is not new to the NEM, because the ACCC has in the past imposed conditions on specific parties' participation in the SRA contracting process (e.g. capping the number of IRSR units Snowy Hydro can bid for).

E.3.4 Managing counter-price flows

E.3.4.1 CRA draft report recommendations

Under the current Chapter 8A, Part 8 Network Constraint Formulation derogation of the Rules, in instances where NEMMCO considers that counter-price flows will lead to the accumulation of negative settlement residues, it can use a discretionary constraint formulation to stop this accumulation. CRA noted that this derogation means adverse bidding behaviour is being addressed through constraint formulation and that this will reduce short-term bidding behaviour when adverse bidding behaviour is not presented and will complicate the dispatch process. It added that negative residues can occur as part of the economically optimal solutions to dispatch around a network loop, and therefore using constraint formulation to address this is inefficient.

CRA's view was that this approach is appropriate in the short-term but that in the long-term such a derogation would decrease efficiency as more and larger loops are created in the network. It recommended that the derogation be allowed to continue and that the use of a simple constraint on network transfers to minimise negative settlement residues by NEMMCO should also be allowed. CRA's preference was to use clamping of the interconnector instead of an Option 1 formulation to address negative residues.

However, CRA advised that another mechanism which is external to the dispatch process should be implemented to address inefficient bidding behaviour. It suggested that a contracting mechanism (i.e. CSP/CSC) be assessed as a longer term and more general instrument to influence bidding and deal with negative IRSRs.

E.3.4.2 Submissions summary

There was a mixed response to CRA's recommendation to continue the derogation that enables NEMMCO to intervene to manage counter-price flows.

ERAA, NGF, Southern Hydro, Ergon Energy and Powerlink supported NEMMCO intervention to manage counter-price flows to restrict negative residues forming. Most of these submissions agreed with CRA that this is a temporary measure and that the intervention will face problems if increased loop flows appear between pricing regions.[363]

Origin Energy argued against the current intervention to manage counter-price flows, claiming that it did not impart effective discipline on participants nor did it lead to a satisfactory allocation of access to market when constraints bind. Hydro Tasmania stated that the proposals do not adequately address the issue of negative settlement residues and that the different treatment of local generation to

[363] Southern Hydro stated that the CSP/CSC mechanism should be developed for more persistent constraints or where loop flows make the current regime unworkable. Ergon Energy stated that continued intervention to limit negative residues was supported but should be reviewed once major AC transmission loops appear between pricing regions.

interconnector flows allowed under the derogation is not consistent with a national market.

The Queensland Generators, on the other hand, thought that negative residues should be funded out of auction proceeds. AGL disagreed with CRA's recommendation. Because negative residues may arise from economic dispatch, it supported a better funding mechanism for negative residue rather than intervention by NEMMCO and the artificial reduction of interconnector capacity.

The Group suggested that instead of the current intervention to minimise negative settlement residues, a more robust and transparent approach to reducing the occasional counter-price flow outcomes of Option 4 could be achieved by implementing a NEMDE forward-looking run. In effect, this would involve a double run of the NEMDE after ramping back inter-connector flow if the first run of the NEMDE showed that counter-price flows would occur. The Group considered the operating speed of the NEMDE sufficient for this approach to be feasible.

E.3.4.3 CRA Final Report: further comments

CRA reaffirmed the recommendations from its Consultation Report. It added that negative residues could be controlled by limiting flow on interconnectors even though this may also curtail efficient dispatch. It also noted that future development of the network is likely to lead to more occasions when anything but a direct physical representation will reduce efficiency of dispatch, especially as more and larger loops are created in the network due to normal expansion. Therefore CRA's preference is for a constraint contract and pricing mechanism, as it offers the opportunity for contracts to be employed to alter the incentives on market participants to encourage bidding in a manner that also limits flow on an interconnector without the need to resort to flow limits.

E.3.5 Constraint contract and pricing mechanism

E.3.5.1 CRA draft report recommendations

CRA made the following recommendations and observations:

- There should be a selective introduction of contracting and pricing of network congestion within and between regions where there are economic benefits that would otherwise be lost. This would create incentives for more efficient responses to congestion.

- Selective implementation of a contracting and pricing mechanism should be triggered when congestion passes an impact threshold. However, region boundary change should be used for significant and persistent constraints.

- The defining characteristic of this mechanism should be to create incentives for responses to manage particular constraint situations rather than to hedge against price differences.

- Voltage control and network support agreements are forms of a contracting and pricing mechanism which currently operate in the NEM.

- CRA developed the Constraint Support Pricing (CSP)/Constraint Support Contracts (CSC) mechanism. The CSP component would provide pricing incentives to respond to congestion (CSP) while the CSC component would provide price insurance.

- Due to the sensitive commercial impact of introducing such a regime, an operational investigation with considerable involvement from market participants should be instituted to assess implementation.

- Criteria should allow for the introduction of specific contracting and pricing for a constraint on a case by case basis.

E.3.5.2 Summary of submissions

Views were divided as to whether a contract and pricing mechanism would be required. Furthermore, most submissions found that the CRA report did not provide sufficient detail on how such a regime would be implemented. Many commented that the key issues of any mechanism would be how to allocate contracts and how to manage generators exposed to negatively priced contracts. The other difficulty raised in regard to contracts was how to define the expected efficient output of each generator. Some submissions recognised that there will never be agreement from market participants on the allocation methodology and that the decision will involve winners and losers.

The Queensland Generators stated that a mechanism external to the dispatch process is preferable to addressing inefficient behaviour, and accepted CRA's CSP/CSC mechanism in principle, subject to further assessment, especially in the areas of allocation and governance.

Enertrade thought the current arrangements for addressing intra-regional constraints—namely NSAs and constrained-on compensation payments—do not do enough, but it wanted to see more detail on the CSP/CSC scheme before endorsing it. Its initial view was that CSP/CSC arrangements would not be effective in managing intra-regional constraints that do not have a direct or indirect inter-regional impact because they would not generate net income for generators who relieved the constraint. Enertrade also considered it important to examine all options, including possible improvements to the existing NSA and constraints on direction arrangements. It also stated that in relation to the CSP/CSC regime, dynamic changes in the right-hand side of constraint equations would make it difficult for generators to predict and dispatch to their relative allocations under CSCs.

Snowy Hydro strongly supported the proposed CSP/CSC regime. It thought such a regime would eliminate the current perverse bidding incentives and would remove the requirement for intervention actions by NEMMCO (either to maintain system security or to minimise negative residues) and hence would firm up IRSRs.

Origin Energy supported the implementation of a CSP/CSC regime to address significant congestion in-between boundary reviews, but only to the extent that an acceptable allocation methodology could be developed for CSCs.

Ergon Energy disagreed with the use of CSP/CSC as an effective congestion management mechanism on the grounds that it depends on some deemed average impact that the generator has on a constraint. It noted that the real-time impact would not be constant. The deemed generator's parameters would need to be updated regularly to maintain some degree of consistency with physical power-flow behaviour. Ergon also considered that the CSC would be a non-firm hedging instrument. Overall, it thought CRA's proposed CSP/CSC arrangements would lead to nodal pricing; and in its submission Ergon provided an analysis of Queensland and suggested that locational energy prices would not significantly affect generator investment for at least the next decade. Its view was that CRA had underestimated the amount of central control and regulatory intervention required to implement the proposed regime.

The Group did not support the CSP/CSC proposal because it thought the primary mechanism for managing significant network congestion should be the regional boundary criteria.

InterGen said the allocation of CSCs should ensure that incumbents' generators were not disadvantaged. It considered it essential that contracts be allocated to existing generators free of charge so that they did not suffer significant revenue or value changes within a region review period. Failure to allocate to existing generators would create a major flaw in the logic for the proposed regime and would fail to achieve the desired outcomes.

Macquarie Generation thought a CSP/CSC regime unnecessary because there are only a few instances of intra-regional congestion in the NEM. It argued that the proposal for periodic assessment of region boundaries combined with the transmission augmentation framework should be sufficient.

Powerlink considered current intervention under the derogation to be a better measure than the proposed CSP/CSC mechanism. It thought the CSP/CSC regime proposed by CRA would not provide the right investment signals to TNSPs to alleviate the congestion.

The ACCC commented that more work is required on the full nodal pricing solution, especially on the implementation costs/issues, and attached a report from IES showing that the potential benefits from nodal pricing are significant.

The ACCC also said that further work is needed on CSP/CSCs, especially on the issue of allocation. Its submission contained a paper on CSP/CSCs by Dr Biggar, which noted that the CSP part of CRA's proposal provided the correct pricing signals to generators in the event of an intra-regional constraint. However, Dr Biggar raised a number of concerns with respect to CSCs, in particular that it is not clear how these grandfathered rights would be determined. He demonstrated that if the grandfathered rights were set in a particular way—specifically, equal to the dispatch of the generator under the existing arrangements—then no generator nor the system operator was left worse off as a result. However, he thought that any attempt to define a set of grandfathered rights would be difficult and contentious. In addition to the issue of how to allocate these rights, it was also not clear for what period of time these rights would be set and how rights would be reallocated in the event that new generation comes on line in an area where an intra-regional constraint occurs. Further, the party responsible for the determination and allocation of these rights must be established. The ACCC also noted that CSPs would provide the correct pricing signals to generators but not to load.

Taken together, the submissions indicated that more work and detail are required on the following:

- allocation of CSCs;
- management of potential "property rights" issues;
- governance frameworks that are likely to be implemented;
- potential arrangements for liability and accountability;
- commercial risk management issues;
- who would identify the need for CSP/CSC and what criteria or threshold would apply in implementing this regime?
- how would NEMMCO use the surplus revenues from this regime? —would they be auctioned or allocated? who would they go to? on what basis would this be determined?
- who would be the winners and losers out of this process?
- would retailers be allowed to hold CSC?

Some of the submissions commented on the possible triggers for a CSP/CSC implementation. The Group considered that the trigger threshold for any CSP/CSC implementation should be based upon the same methodology as region boundary assessments, noting that the trigger thresholds set for the regional boundaries would determine the thresholds for any CSP/CSC implementation. As CRA said, given that the CSP/CSC would be a temporary substitute for any regional boundary, the implementation triggers would be lower than those for regional boundaries. AGL was concerned that temporary measures like CSP/CSC would become entrenched and it therefore proposed that any application of these mechanisms be strictly time-limited.

Snowy Hydro recommended the CSP/CSC implementation process be triggered by NEMMCO whenever constraint costs exceeded $10 000. It argued that the total transaction and implementation cost for a specific CSP/CSC location would be extremely low.

InterGen stated that the criteria for selecting locations for CSP/CSCs needed to be very tight and that alternatives such as NSA would be equally effective. It added that CSP/CSC criteria should be a net benefit test and that participants' transactions costs should be included in that assessment.

E.3.5.3 CRA Final Report: further comments

CRA maintained its position that a flexible localised arrangement to create incentives to manage the effects of congestion should be developed to complement the proposed region boundary review process. It recommended that market authorities develop proposals for an intra-regional contracting/pricing mechanism based upon the broad design of its proposed CSP/CSC mechanism. It considered that the contracts should be crafted to suit characteristics and objectives of each application that are most important.

Although CRA acknowledged that the number and scope of such localised mechanisms could be set by policy requirements, it thought that the regime would be best suited to managing a small number of local conditions under the broader regulatory framework because it would become overly complicated if used universally across the NEM. CRA's expectation, based on the history of the NEM and analysis of the potential level of congestion under the investment framework, was that the regime might be applied to a relatively small number of key points of congestion, say five, at any one time across the NEM.

CRA also recognised that the proposal could be applied to manage the potential misuse of localised market power that occurs with congestion. It noted that this sort of policy response is not new to the NEM: the ACCC has, in the past, imposed conditions on specific parties' participation in the SRA contracting process.

E.3.6 List of submissions to CRA draft report

All of the following made Regional Structure Review Submissions:

- Queensland Generators—comprises CS Energy, Enertrade, InterGen, Stanwell and Tarong Energy
- Australian Competition and Consumer Commission (ACCC)
- Australian Gas Light Company (AGL)
- Energy Networks Association (ENA)
- Southern Hydro
- Origin Energy
- TXU
- Creative Energy Consulting
- CS Energy
- Delta Electricity
- Energy Retailers Association of Australia (ERAA)

- Enertrade
- Ergon Energy
- Hydro Tasmania
- InterGen (Australia) Pty Ltd
- Macquarie Generation
- National Generators Forum (NGF)
- Powerlink
- Snowy Hydro
- Stanwell
- Tarong Energy
- The Group—comprises AGL, Delta, Loy Yang Marketing Management, Macquarie Generation, Stanwell, Yallourn, Powerlink and TransGrid
- TransGrid
- Gallaugher and Associates of Australia

E.4 Network Support and Control Services

Network Support and Control Services (NSCS) are those services procured and delivered by either Transmission Network Service Providers (TNSPs) or NEMMCO for the purpose of managing network flows to ensure that the power system is operating securely and reliably. The framework for NSCS procurement and delivery have been subject to repeated reviews since 1997. This section describes the historical development of the arrangements and provides a comprehensive definition of existing NSCS and the current rationale for the various forms of service provision.

E.4.1 History of Network Support & Control Services

This account of the development of NSCS provides a context for understanding how the definition of key services has evolved and how various reviews throughout the history of the NEM have impacted on responsibilities for the procurement and delivery of NSCS.

E.4.1.1 Ancillary services pre market start

The National Grid Management Council

In the early history of the NEM's development, when the National Grid Management Council (NGMC) was the driving force, service categories were not clearly or consistently defined among the vertically integrated (State-owned) electricity entities. Consequently, approaches and definitions adopted by the NGMC were the first attempt to classify services and suggest responsibilities for service procurement and delivery within a national electricity market.

An NGMC paper from November 1994 sets out the earliest available thinking on the subject of ancillary services in a national electricity market.[364] The NGMC's philosophy in that paper was that, wherever possible, markets in ancillary services would be run by the system operator:

> The objective of the electricity market is to increase economic efficiency through competition. In keeping with this objective, the level of services required to support the operation of the power system and their sourcing should be determined through market forces wherever possible. However, it is recognised that some aspects of these services can make this difficult to achieve. These include:
>
> - shared benefits can lead to free rider problems;

[364] *National Grid Management Council, National Electricity Market Project, Ancillary Services & Reserves*, Market Trading Working Group, (draft for comment) version 0.1, 15 November 1994.

- provision of services may be difficult to quantify and monitor;

- the service may be achievable by different mechanisms which are not directly comparable;

- the requirement may be localised, with a local monopoly [in] its provision; and

- fully market based provision of the service may be complex and not cost effective.

> As a result, pragmatic and less ideal arrangements may have to be considered in the interim and the level of service may have to be determined centrally rather than via market forces. The cost of each service provided may be determined by market forces or as a result of commercial negotiations between the service providers and the System Operator. In any commercial negotiations, the System Operator will examine the opportunity costs of various alternatives. The costs of providing these services should be shared on an equitable basis between all participants.[365]

Definitions of service categories inevitably evolved as the structure of a national market and its rules for operation were developed. The NGMC proposed the following as one possible categorisation of ancillary services:

- **System security**
  - system security control schemes (e.g. islanding, generator reduction control schemes); and
  - black start and restart capability.
- **Frequency control**
  - generator governor action;
  - automatic generation control (AGC);
  - automatic load shedding schemes (under frequency tripping); and
  - demand reduction schemes.
- **Voltage control**
  - generator reactive capability;
  - automatic load shedding schemes; and

365 Ibid., pp.2-3.

– generator network support.[366]

Although the NGMC work probably set the scene for future development of NSCS, no mechanisms for procurement and delivery were formalised at that stage.

NEM1 Phase 2, Ancillary Services Project

Following the initial efforts of the NGMC, the next significant step in the development and consolidation of ancillary services after the early draft stages of the NGMC Code of Conduct, was in a 1997 report for the NEM1 Phase 2, Ancillary Services Project.[367] This report established arrangements for the procurement of ancillary services prior to market start, the intention being for VPX and TransGrid to enter into ancillary service contracts that would be novated to NEMMCO on the commencement of the NEM. An extract from the report outlining the definition of services and the project objective is shown in Box E.1.

---

[366] Op. cit., p.7.

[367] *NEM1 Phase 2 Ancillary Services Project Report, Recommendations for the procurement of ancillary services and for reimbursement by the market*, VPX and TransGrid, May 1997.

Box E.1: Extract from Ancillary Services Project Working Group report: definition of services and project objective

<u>Definition of Ancillary Services in the context of NEM1 Phase 2</u>

"Ancillary Services are those services performed by generation, transmission and control equipment which are necessary to support the transmission of electric power from producer to purchaser given the responsibilities of the operating authorities to maintain safe, secure and reliable operation of the interconnected power system.

The services include both mandatory services and services subject to competition."

<u>Project Objective</u>

The objective of the NEM1 Ancillary Services project is:

"To achieve a consistent set of arrangements for the procurement of and payment for the required Ancillary Services in line with the above definition which (in priority order):

1. will be practical to implement by July 199;

2. do not require significant investment in new monitoring hardware and/or IT facilities to administer;

3. provide adequate short and long term price signals to users and providers of the services; and

4. are capable of operating until NEMMCO has completed its review of the ancillary services arrangements in accordance with Clause 3.13.1 of the draft National Electricity Code."

With respect to support and control services, the report established sub-categories of ancillary services as follows:

- **Voltage control –** which includes services from:
  - generator unit reactive;
  - transmission plant reactive;
  - other reactive plant (e.g. hydro machines as SynCons, distributors and extra high voltage customers);
  - emergency load shedding schemes; and
  - on load tap changers on transformers.
- **Stability control** – which includes services from:

- excitation systems;
- power system stabilisers; and
- rapid generating unit unloading.

- **Network loading control –** which includes services from:
  - automatic generation control (AGC);
  - rapid generator unloading; and
  - interruptible load shedding.

The recommendations that emerged from the Ancillary Services Project Working Group report formed the basis of Schedule 9G of the Code.[368] Schedule 9G articulated arrangements for procurement and cost recovery of all ancillary services:

- frequency control;
- voltage control;
- stability control;
- network loading control; and
- system restart.

Schedule 9G was deemed to be a more practical arrangement (than that in Chapter 3 of the Code) for the start of the NEM, and remained in place until the completion of the first ancillary services review.

E.4.1.2 Ancillary services post market start

The first ancillary services review

The first ancillary services review was a requirement of the Code as it existed at NEM-start:[369]

> (c) In conjunction with its obligations under clause 3.8.9(d), NEMMCO must investigate, consult with Code Participants in accordance with the Code consultation procedures and report to NECA within 2 years of market commencement on the possible development of market-based arrangements for the provision of ancillary services, including a short-term market in which Market

[368] A derogation of clause 3.11 in relation to acquisition, delivery and settlement of ancillary services. Schedule 9G was a Jurisdictional derogation that, in essence, sought to extend VPX / TransGrid pre-market arrangements, but also included some specific arrangements for Queensland.

[369] Clause 3.11.1. This review clause (with minor modifications regarding timetables) was included in the Code until version 5.6 was replaced by version 5.7 (Gazetted 9/8/01).

> Participants which are not parties to ancillary services agreements may submit offers for the provision of regulating capability or contingency capacity reserve.

The review to which the clause refers was completed in August 1999.[370] The report of the review made this general comment on the ancillary services arrangements that prevailed in the NEM's first two years:

> None of the parties most involved in the current arrangements finds them satisfactory. Contract negotiations for the initial round were protracted and difficult both for NEMMCO and the parties that responded to NEMMCO's invitation to tender. Generators feel they are unfairly and unreasonably required to provide too many services for free under the mandatory requirements of the Code and connection agreements. Retailers feel they are unfairly and unreasonably required to pay for all services, when they consider that they are not the cause of the requirement (although their customers may be). Many of these real or perceived problems are inherent to the central procurement of ancillary services overlaying a competitive energy market.[371]

With respect to recommendations for future arrangements for NCAS—that is, all ancillary services other than frequency control and system restart—the report of the review stated:

> Initial arrangements for voltage control (contingency and continuous) services are proposed as follows:
>
> - NEMMCO would remain responsible for the dispatch of voltage control services and for ensuring that there are sufficient voltage control services from a power system security perspective.
>
> - Contracts (for hedging/procurement) would be written between generators and TNSPs / NEMMCO depending on the clarification of responsibilities for reactive reserve.
>
> - For reactive generation that is required due to the connection of a generator and that is consequently specified in a connection agreement, no cost associated with reactive reserve. For reactive above this level, negotiated contracts that specify availability and enablement components. Compensation to be payable if generating plant needs to be backed off to provide the reactive service.
>
> - Although testing of an AC load flow nodal pricing model that would price reactive energy in the context of energy spot trading is proposed,

[370] *Evaluation of options for an ancillary services market for the Australian electricity industry, A project commissioned by the NEMMCO Ancillary Services Reference Group, Final Report*, Intelligent Energy Systems, August 1999.

[371] Ibid. p.vii.

the co-dispatch of generator reactive capability with the energy spot market may not be warranted or feasible in the transitional phase.

Initial arrangements for Stability and Network Offloading [or network loading control] services are proposed as follows:

- Negotiated contracts are recommended as the most appropriate arrangement for procuring stability and network loading services for the foreseeable future.

- The arrangements would require NEMMCO to provide information on potential schemes and the service that they would provide. This would need to be included in the Statement of Opportunities.

- Further consideration of markets in NCAS should be preceded by a review of the basis for and structure of the currently defined generic (security) constraints applied in the SPD.[372]

The recommendations of this first review were (largely) implemented as proposed.[373] In response to the final item listed above, Code changes requiring further review of non-market ancillary services (the NCAS review) were made, with the insertion of a requirement in clause 3.1.4 of the Code[374] as follows:

(a1) *NEMMCO* must review, prepare and *publish* a report on:

…

(4) the provision of *network control ancillary services* including:

(i) a review of the responsibilities of *NEMMCO* and *Transmission Network Service Providers* for the provision of *reactive power support*;

(ii) a review of the formulation of those generic *network constraints* within *central dispatch* that are dependant on the provision of *network control ancillary services*; and

---

[372] Ibid. p.xiv.

[373] NCAS continued to be procured on the basis of long-term contracts (per Schedule 9G of the Code) until a new NCAS tendering process [supported by new clause 3.11 in Version 5.7 of the Code (Gazetted 9/8/01) was implemented for NCAS contracts commencing 1 July 2002 and SRAS contracts commencing 1 July 2003.

[374] Version 5.7 of the Code (Gazetted 9/8/01).

(iii) a program to assess the potential implementation of market mechanisms for the recruitment and *dispatch* of *NCAS*.

(a2) In conducting the reviews under clause 3.1.4(a1) …

(2) elements of the reviews set out under clauses … 3.1.4(a1)(4)(iii) must take into consideration the results of the [*NECA* report that analyses the outcome of trade in *market ancillary services* through the *spot market*.]

The ACCC's authorisation of the Code changes incorporating the NCAS review indicated:

> … the Commission notes a number of reviews may impact upon the future provision of NCAS, including:
>
> - the review of the integration of network services and energy markets [aka NECA's review of the integration of energy markets and network services (RIEMNS)];[375]
> - the market and system operator review [aka the Market and System Operator Review Committee (MSORC) process];[376]
> - the Code change process arising from the network pricing review [aka NECA's transmission and distribution pricing review]; and
> - the review of the treatment of constraints in the market.
>
> … in relation to NCAS the ancillary services review will need to encompass the outcomes of the other reviews listed above, and in particular the outcomes of the MSORC.
>
> The MSORC is considering the most appropriate allocation of roles between NEMMCO, as the system operator, and TNSPs as service providers. The outcome of this review will determine which agency should be responsible for procuring NCAS, dispatching NCAS, recovering the costs of NCAS and determining the most appropriate methodology for recovering the costs.

[375] See section below.

[376] See section below.

> … in terms of timing, any review considering possible market arrangements of future development for NCAS will have to commence after the outcomes of other relevant reviews are known.

The RIEMNS and MSORC process are discussed further in following sections.

The reference to "the review of the treatment of constraints in the market" was probably a reference to either or both of: the NEMMCO review on formulation of intra-regional constraints;[377] or the IES review on optimising combined secure and economic dispatch, conducted on behalf of the Reliability Panel.[378] Each of these reviews was scheduled for around that time. The outcomes of these reviews had no apparent impact on fulfilment of TNSP/NEMMCO responsibilities for NSCS.

The requirement to conduct an NCAS review per Clause 3.1.4(a1)(4) remains in the current version of the National Electricity Rules, although the review referred to has yet to commence for the following reasons:

- the review of network control ancillary services alluded to in clause 3.1.4(a1)(4) had to take account of the NECA report alluded to in clause 3.1.4(a2)(2)—a final version of this NECA report was not released prior to NECA being disbanded;[379] and

- given the possibility of NEMMCO's NCAS review overlapping with the considerations of our CMR, NEMMCO sought and received our agreement to delay the commencement of the NCAS review until such time as the CMR was able to provide some guidance as to appropriate direction.

The RIEMNS process

The review of the integration of energy markets and network services (RIEMNS) resulted in a report[380] that did not impact in any substantial way on the development of network support and control services, although RIEMNS did touch on a couple of issues relating to the management of network congestion:

- provision of network outage information to the market by TNSPs; and

- a proposal for NECA to develop a network performance framework.

---

[377] See NEMMCO (Network Constraints Reference Group), *Formulation of intra-regional constraints, Issues and options paper*, Version No. 2 (January 2002) available at: http://www.ksg.harvard.edu/hepg/Papers/Nemmco%201-02%20trans%20price%20148-0061.pdf.

[378] Intelligent Energy Systems (IES), *Optimising combined secure and economic dispatch, Report to the Reliability Panel* (February 2003).

[379] This report on frequency control ancillary services has subsequently been made available – see NECA, *Review of market ancillary services*, Final report (June 2004), available at: http://www.nemmco.com.au/ancillary_services/160-0287.pdf.

[380] NECA, *The scope for integrating the energy markets and network services, Stage 1 final report*, August 2001. No subsequent stages of the RIEMNS process were undertaken.

Code changes requiring TNSPs to provide network outage information were authorised. However, the ACCC considered that NECA's proposed network performance framework duplicated powers already vested in the ACCC.[381] Consequently, the ACCC did not authorise NECA's proposed Rule changes on the development of a network performance framework.

The MSORC process

The report of the MSORC was expected to be a key element in the evolution of responsibilities for ancillary services. The NEM Governance and Liability Steering Committee, comprising the NEM jurisdictions and the Commonwealth, established MSORC in late 1999/early 2000 to assist the Steering Committee to, *inter alia*:

> address governance issues, including … the allocation of responsibilities for MSO System Security and System Operation functions between NEMMCO and the TNSPs.[382]

With respect to allocation of responsibilities for network control, the members of MSORC were unable to reach agreement. The report noted:

> Although it is not a core issue for the MSORC review, the MSORC has given some consideration to the allocation of responsibilities between NEMMCO and the TNSPs regarding the procurement, scheduling, dispatch and funding of NCAS in the NEM.
>
> The MSORC finally resolved to put this issue to one side because a final decision on it would not change any other MSORC recommendations. The MSORC notes that current code change proposals before the ACCC call for NEMMCO to undertake a further review of this issue during 2001. It is suggested however that before NEMMCO can reasonably be expected to find a satisfactory resolution to this issue, it will need some policy decisions in the form of much clearer regulatory principles and guidelines from the jurisdictions and/or the ACCC concerning the future scope of TNSPs' regulated network services.[383]

The recommendations of the MSORC report were never implemented.

---

[381] See ACCC, *Determination: Stage 1 of integrating the energy market and network services* (October 2002), available at: http://www.accc.gov.au/content/trimFile.phtml?trimFileName=D03+15425.pdf&trimFileTitle=D03+15425.pdf&trimFileFromVersionId=756520.
The recently commenced reporting of total constraint cost measures by the AER is a second generation manifestation of the "powers already vested in the ACCC".

[382] From the MSORC terms of reference, *System Security & System Operation Review Report 1 (Final Draft) System Operator Functions & Responsibilities*, December 2000, Appendix 1.

[383] Ibid, p.11.

NECA report on generator rebidding

The next change in the network control ancillary services environment came with a requirement for NEMMCO to use NCAS to increase the benefits of trade from the spot market. The requirement arose in the context of Code changes designed to address concerns regarding generator rebidding behaviour.

NECA's inquiry into rebidding resulted in a 2001 report[384] that included some proposals for tackling short-term price spikes and for removing opportunities for generators to exploit inefficiencies arising from: transfer limits across interconnectors; short-term loading constraints; dispatch processes; and network services. With respect to these inefficiencies the report said:

> Our evidence to the South Australian electricity taskforce[385] drew attention to four specific examples of these sorts of inefficiencies and to the need to take urgent action to improve the operation of the market in order to remove the opportunities they create for generators to exploit those inefficiencies:
>
> **efficiency of dispatch**. The draft report of our review of the scope for integrating the energy market and network services pointed to the tendency for constraint equations to be written relatively to favour local generation. This is the case, for example, in relation to Ladbroke Grove in South Australia and generators in south-east Queensland. This arguably breaches one of the fundamental objectives of the market, set out in the Code, that intrastate trading should not be treated more or less favourably than interstate trading. It can, and does, lead to relatively more expensive plant being dispatched even where cheaper electricity would have been available for import across an interconnector. NEMMCO recently established a reference group to address these issues. That group should report urgently. Its focus should be on ensuring the essential integrity of the fundamental anti-discriminatory objective of the Code and the objective of maximising the benefits of trade. To the extent that meeting any second-order technical obligations imposed by the Code conflicts with fulfilling that overriding objective, those technical obligations should be rewritten. A common complaint from participants is the perceived complexity of the constraint equations, in part as a result of inconsistent formulation. Work is required to increase the quality of constraints to enhance the usability of this critical information; and
>
> **network services**. We believe there is scope within the existing arrangements for NEMMCO to make more use of, for example, load shedding, real and reactive support and scheduling, and unit commitment contracts. Network services, including pre-emptive unit commitment contracts and real-time ancillary services, could be developed to help to cope with the consequences

[384] NECA, *Generators' bidding and rebidding strategies and their effect on prices*, Report, July 2001.

[385] The SA Government established the South Australian National Electricity Market Taskforce in March 2001 to assess the impact of the National Electricity Market (NEM) on business and domestic customers in South Australia.

of interconnector constraints. The recently-established gatekeeper project is working towards possible solutions to some of these issues. The extent of NEMMCO's current power to enter into such contracts is, however, uncertain. We therefore recommend a change to the Code to give NEMMCO clearer and wider powers to enter into such contracts.

NEMMCO should take the most urgent possible action to address these inefficiencies. The changes we recommend to the Code will help facilitate that action.[386]

As a consequence of the NECA report and subsequent application to amend the Code, the ACCC authorised a change to clause 3.11.3(b) of the Code as follows (insertions from version 7.5 are underlined):

NEMMCO must develop and *publish* a procedure for determining the quantity of each kind of *non-market ancillary service* required for *NEMMCO*:

(1) to achieve the *power system security and reliability standards*; and

(2) where practicable to enhance *network* transfer capability whilst still maintaining a *secure operating state* when, in *NEMMCO's* reasonable opinion, the resultant expected increase in *non-market ancillary service* costs will not exceed the resultant expected increase in benefits of trade from the *spot market*.[387]

This revised clause is retained in the current Rules (now renumbered as 3.11.4).

E.4.1.3 Current arrangement for the management of interconnector transfer capability

At present, where interconnector capability is managed, it is managed by NEMMCO; but this applies to only two of the NEM's five interconnectors—Snowy to New South Wales and Victoria to Snowy. Arguably, these cases represent a "legacy assignment" of responsibilities, dating back to the start of the market in 1998. Transfer capability on the VIC-SA and QNI links is not actively managed by NEMMCO or the respective TNSPs.

However, there are likely to be strong commercial incentives on Basslink's asset owner to effectively manage the transfer capability of the DC link, given it is an MNSP whose income stream depends (in part) on the available capacity of the link.

The procedure governing how NEMMCO manages transfer capability on the Snowy to New South Wales and Victoria to Snowy interconnectors is described below.

---

386 NECA, *Generators' bidding and rebidding strategies and their effect on prices*, Report, July 2001.

387 Clause 3.11.3(b)(2) first appeared in Version 7.6 of the Code (Gazetted 16/1/03) and remains in the current version of the Rules.

First, NEMMCO sources reactive support from Snowy Hydro generators, which operate in Synchronous Condensor (SynCon) mode. When operating in SynCon mode, Snowy Hydro's generators either inject or absorb reactive power (MVArs), which is used by NEMMCO to manage the voltage level drop along the long interconnection between Melbourne and Sydney. Without this SynCon service, the interconnectors' transfer capabilities would be substantially lower unless TransGrid and VenCorp invested substantial capital in the provision of alternative, network-based sources of reactive power and voltage control.

Prior to the start of the NEM, the reactive power support for both of these interconnectors was managed by the State Electricity Commission of Victoria (SECV) via a contract with Snowy Hydro Trading Pty Ltd. The SECV probably did this as part of its management of Victoria's electricity entitlements under inter-governmental agreements on the Snowy Mountains Hydro Electric Scheme.[388] The SECV's creation of the Victorian Power Exchange (VPX), a market and system operations arm, resulted in responsibility for managing the reactive support contracts passing to VPX. At the start of the NEM in December 1998, NEMMCO took over the functions of VPX, and as a consequence responsibility for the interconnector support contracts passed to NEMMCO.[389]

There does not appear to have been any consideration of whether, in the long-term, TNSPs or NEMMCO would be the more appropriate party to manage the reactive support contracts, having regard to the incentives on TNSPs versus NEMMCO. The purpose of the report was solely to establish savings and transitional arrangements for ancillary services to be managed once the NEM started. These interim arrangements were to be reviewed by NEMMCO within two years of market start (as specified in Clause 3.13.1 of the draft National Electricity Code).[390] The report recommended temporary arrangements, such that NEMMCO would be the counter-party to ancillary service contracts entered into by TransGrid/VPX, following the novation of the contracts to NEMMCO on market start. Arguably, the increased power transfer capability through the Snowy region ultimately provides reliability of supply benefits to customers in the importing region(s), a principle recognised by market designers before market start in 1998.[391]

---

388 *Snowy Mountains Hydro-electric Agreements Act 1958 No.20 (NSW).*

389 See TransGrid & VPX 1997, "*National Electricity Market (NEM1, Phase 2) — Recommendations for the Procurement of Ancillary Services and for Reimbursement by the Market*", for TransGrid and Victorian Power Exchange, by NEM1 Ancillary Services Project, May 1997, p. ix, "Transition to NEMMCO Management"; Appendix C, Attachment 2, items 6 (Synchronous condensor spinning reserve); Table 4.2.2.2; and Appendix D, sections 2.2.1 and 2.2.2.

390 NEMMCO's 1999 Ancillary Services review recommended the establishment of markets for Frequency Control Ancillary Services (FCAS) and a further review of arrangements for Network Control Ancillary Services (NCAS). To date, the basic NCAS arrangements remain unchanged from those established at market start. Two other reviews — RIEMNS and MSORC — each failed to address reforms to NCAS.

391 This beneficiary pays principle appears to have been recognised both as a general principle (*ibid*, p.5) and in the way reactive power expenses were to be recovered on a location specific basis *(ibid*, p.13). Specifically, appears that a form of Cost Reflective Network Pricing (CRNP) was used to recover the unbundled costs of providing reactive support — "MVAr demand charges to

Second, NEMMCO procures a network loading control service for imports along the Snowy-VIC directional interconnector, which involves arming a Victorian smelter to trip. This network loading control scheme can raise the maximum secure Snowy-VIC transfer limit by 200 MW (currently from 1 700 MW to 1 900 MW) and is of most value (and generally only utilised) when there are potential shortfalls in supply in VIC-SA during periods of high demand.[392] Like the reactive support service discussed above, prior to the start of the NEM the SECV and then VPX contracted for this load-tripping service, with the responsibility for the contract assigned to NEMMCO at market start, where it has remained.[393] Importantly, this smelter load-tripping scheme primarily provides reliability benefits rather than security benefits. To understand this, it is worth considering that in the absence of the load-tripping scheme, NEMMCO could still operate the network securely at the lower Snowy-VIC transfer limit, but this could result in involuntary load shedding in Victoria and South Australia (with resulting VoLL pricing). The system would still be secure in this case, but at the cost of some lost load in VIC and SA. Arguably, it is customers in Victoria and SA who are the principal beneficiaries of the increased reliability arising from the increase in secure transfer capability of the Snowy-VIC interconnector.[394] If this is accepted, it can be argued that the Victorian and South Australian TNSPs should be responsible for procuring the smelter load-tripping service, rather than NEMMCO.

E.4.2 Current approach to service delivery

This section focuses on the current environment for NSCS and outlines:

- the definition of relevant NSCS, the rationale for their procurement, and how they work;
- the guidance provided to TNSPs and NEMMCO in determining what type and how much NSCS should be procured and delivered; and
- some stylised examples of NSCS.

E.4.2.1 Service definition and rationale

NSCS currently procured and delivered include:

---

distributor based on 10 highest reactive demands at each wholesale metering point" (ibid, Table 4.2.2.2).

392 Arming the smelters for rapid off-loading enables the (higher) 5-minute thermal limits on the Victoria-Snowy interconnector to be used in dispatch. This network loading control scheme is only used under lack of reserve level 2 (LOR2) conditions, as defined in clause 4.8.4(r) of the Rules, and after NEMMCO has assessed if there is an economic benefit from enabling the service.

393 *ibid*, p. ix "Transition to NEMMCO Management" and Appendix C, Attachment 2, item 8 (Interruptibility service) deals specifically with the smelter tripping service. See also Table 4.2.2.3; and Appendix D, section 2.2.3 of the same report.

394 This beneficiaries pay principle was explicitly acknowledged in Table 4.2.2.3 of TransGrid & VPX report, which states that the recovery costs relating to the smelter rapid unloading scheme is to be based on "CRNP to beneficiaries (charges to distributors)".

- **Network support services**—procured by TNSPs via contracts with third parties (network support agreements or NSAs) via services in the form of:
  - generators agreeing to be constrained-on or -off;
  - loads agreeing to be constrained-on or -off;
  - generators providing reactive power capability (see Box 2), either as a condition of a network connection agreement or under a separate contract;
- **Network control services**—delivered by TNSPs from their own infrastructure as reactive power capability in the form of voltage control from:
  - capacitor banks and reactors;
  - static Var compensators (SVCs);
- **Network control ancillary services (NCAS)**—procured by NEMMCO via contracts with Market Participants (not TNSPs) as either:
  - reactive power ancillary service in the form of voltage control from:
    - generators operating in generation mode;
    - generators operating in synchronous condensor mode (SynCons)[395]; and
    - DC links;
  - network loading control ancillary service—provided via:
    - generator control schemes, for example rapid generator unit loading or rapid generator unit unloading; and
    - load tripping schemes.

[395] Generators operating in SynCon mode do not produce MWs – they operate as a motor (with small or negligible load on the power system), but retain the ability to inject and absorb MVars.

Box E.2: A note on reactive power

Delivery of real power (MWs) and delivery of reactive power (MVars) are complementary services—the power system cannot be effectively operated without control over both MWs and MVars. Control over reactive power injection or absorption is necessary to manage voltage levels at specific locations in a network. Voltage stability is a key form of constraint on the operation of the power system.

Reactive power capability can be delivered via several different technologies.

Dynamic reactive power capability is the ability to change the level of MVar injection or absorption in response to emerging real-time power system conditions. Dynamic reactive power capability can be provided by: generators in generation mode; generators in SynCon mode; SVCs; and DC links.

Static reactive power capability is the ability to inject or absorb MVars at a given level depending on whether the relevant plant is switched on. Static reactive power capability can be provided by: capacitor banks (injecting MVars); and reactors (absorbing MVars). Static reactive plant can be configured to switch automatically in response to network voltage changes.

Voltage stability constraint equations in NEMDE reflect the availability of plant with reactive power capability. When the availability of reactive plant changes, so too will the RHS limits of relevant constraint equations in NEMDE. As RHS limits on constraint equations change, network congestion can be relieved or exacerbated.

Aside from procuring and delivering different forms of NSCS, TNSPs and NEMMCO employ differing rationales for delivering or contracting NSCS:

- TNSPs ensure appropriate levels of NSCS are delivered such that there is the capability to manage intra-regional network reliability at expected peak demand in an effort to meet "intra-regional reliability" obligations.

- TNSPs could procure and deliver NSCS as part of the most efficient package of measures to deliver network capability with net market benefit consistent with the market benefits limb of the Regulatory Test.

- NEMMCO procures appropriate levels of NCAS such that there is the capability to ensure a system-wide secure and reliable network at all times as part of meeting the power system security and reliability standards under the Rules.

- NEMMCO may procure NCAS to assist in maximising the value of spot market trading.

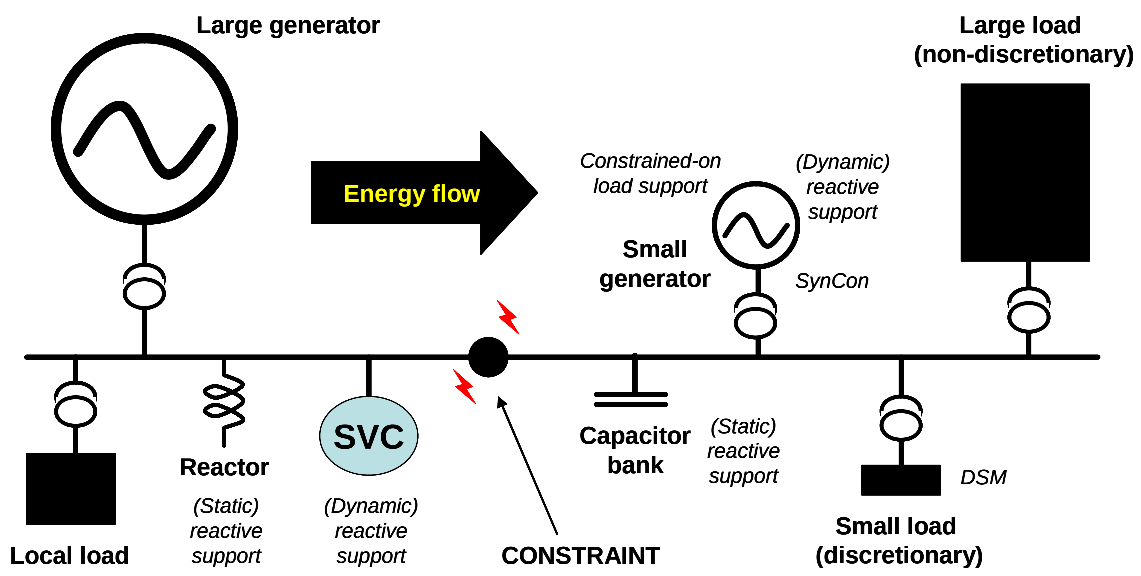
As indicated previously, although various legislative instruments and obligations package TNSP and NEMMCO responsibilities in different ways, the services that

TNSPs and NEMMCO procure and deliver and the outcomes that they seek to achieve are in many ways indistinguishable.

E.4.2.2 How support & control services work

Delivery of network capability can be accomplished with a variety of technologies and combinations of technologies. Most of the requirements for NSCS are highly locationally specific and, by varying the level of real or reactive power at different locations in the network or by operating load control facilities, the level of network congestion can be altered in ways that either reduce or increase the dispatch cost on the spot market for energy. Examples of network infrastructure and NSCS that can be used to facilitate network flows are depicted in Figure E.7.

Figure E.7 Stylised network with infrastructure and support & control services to facilitate network flows



In the stylised network depicted in Figure E.7 energy typically flows from left to right even though there is a constraint in the middle of the network. Constraints are commonly of two forms:

- *thermal limit*—limitation on the amount of heating that network elements can withstand, controlled by increasing or reducing real power (MWs) loading on a specific side of the constraint; and
- *stability limit*—limitation on the ability of network infrastructure to dampen/withstand unanticipated fluctuations in the power system, controlled

by injecting or absorbing reactive power (Vars) at a specific location in the network.

Depending on the constraint form ("thermal" or "stability") and network loading conditions, the constraint could be relieved in a variety of ways as noted in Table E.1.

Table E.1: Use of NSCS technology by either TNSPs of NEMMCO

Technology	Under current arrangements …
Capacitor bank providing static voltage support as MVar injection.	• technology is TNSP owned and controlled – not available to be contracted by NEMMCO.
Reactor providing static voltage support as MVar absorption.	• technology is TNSP owned and controlled – not available to be contracted by NEMMCO.
Static Var compensator (SVC) providing dynamic voltage support – MVar injection or absorption.	• technology is TNSP owned and controlled – not available to be contracted by NEMMCO.
Small generator discretionally controlled to provide: • network support by being "constrained-on"; • dynamic voltage support – MVar injection or absorption – while either: o operating in generation mode; or o operating in SynCon mode.	• constrained-on network support contracted by TNSPs. • voltage support from generators in generation mode contracted by both TNSPs and NEMMCO. • voltage support from generators in SynCon mode contracted by NEMMCO.
Small load providing demand-side management (DSM) as either: • pre-contingent network support (e.g. enabling / arming the rapid unloading of a smelter); or • post-contingent network support (e.g. utilising the rapid unloading of a smelter).	• network load relief services are contracted by both TNSPs and NEMMCO.
"Build out" the constraint via upgraded transmission lines or transformers.	• option only available to TNSPs.

E.4.2.3 Services procured or delivered by TNSPs

Guidance to TNSPs

The mix of assets and the form of NSCS that an TNSP supplies with its own infrastructure, or procures via contract with third parties, will be a function of the relevant standards associated with preventing or managing congestion occurring in the network for each TNSP and the testing of available options through the Regulatory Test.

The standards to be met by each TNSP are unique to that TNSP, and may include:

- requirements outlined in state-based legislation;
- licence conditions imposed by jurisdictional regulators (or ministers);
- technical requirements included in the Rules;
- standards agreed with connected customers;
- formal (and informal) internal long-term planning documents;
- formal (and informal) internal operational and maintenance planning documents;
- standards imposed via regulatory resets conducted by the AER; or
- standards imposed by Standards Australia, or other relevant international standards.

This suite of documentation (listed above) will be collectively referred to here as "TNSP network capability obligations". Any combination of one or more (or even all) of the above may state (or suggest) a need to procure NSCS to ensure the appropriate "standard" is not breached.

Although Network Service Provider obligations are commonly referred to in the context of "reliability", TNSPs must also ensure that supply is robust to credible contingencies, indicating that TNSPs must also consider "security" as a factor. Hence the distinction between reliability and security does not represent a boundary of TNSP responsibility, and so "TNSP network capability obligations" is the preferred generic reference.

Note that the costs of the services procured by TNSPs as support and control services are recovered via their regulated revenues.

Determining the level of procurement

Setting aside (for the moment) procurement of NSCS for purely "market benefit" reasons, the appropriate level of procurement of NSCS is not always straightforward to determine.

Where TNSP network capability obligations are relevant[396], the level of NSCS procured or delivered by a TNSP will depend on the TNSP's interpretation of the applicable instrument(s) and on the mix of infrastructure and services by which the TNSP meets the relevant standard. Subject to funding restrictions established via regulatory resets, there is a degree of flexibility with respect to the mode by which TNSPs will choose to deliver on network capability obligations. The choice is between:

[396] That is, the "market benefits" limb of the regulatory test does not apply.

- new or augmented TNSP owned infrastructure:
  - transmission lines or transformers; or
  - reactive power capability in the form of:
    - capacitor banks or reactors; or
    - static Var compensators (SVCs);
- network control mechanisms using the TNSP's infrastructure (e.g. splitting/switching schemes that deliberately break a point of connection between network elements to increase network capability at the cost of a probabilistic loss of network reliability); and
- network support services procured by TNSPs via contracts with third parties in the form of:
  - generators agreeing to be constrained-on or -off;
  - loads agreeing to be constrained-on or -off; or
  - generators providing reactive power capability.[397]

Where the "markets benefits" limb of the Regulatory Test is applied, some mix of any or all of the above modes for delivery of network capability is also likely to be appropriate, the optimal mix being that which maximises net market benefit.

E.4.2.4 Services procured by NEMMCO

Guidance to NEMMCO

NEMMCO's obligations with respect to procuring NCAS are most clearly expressed in clause 3.11.4(b) of the Rules, which states:

> NEMMCO must develop and publish a procedure for determining the quantity of each kind of [network control ancillary service][398] required for NEMMCO:
>
> (1) to achieve the *power system security and reliability standards*; and

[397] Dynamic voltage support (MVar injection or absorption) either as part of the amount a generator is required to make available as a condition of its connection agreement with the NSP; or as a separately contracted amount in addition to that available via connection agreements.

[398] Clause 3.11.4(b) actually refers to "non-market ancillary services" that comprise both *system restart ancillary services* (SRAS) and *network control ancillary services* (NCAS). Procurement of SRAS is not relevant to this paper.

(2) where practicable to enhance *network* transfer capability whilst still maintaining a *secure operating state* when, in *NEMMCO's* reasonable opinion, the resultant expected increase in *non-market ancillary service* costs will not exceed the resultant expected increase in benefits of trade from the *spot market*.

The formal descriptions of NCAS are provided in NEMMCO's amended procedure for determining quantities of network control ancillary services.[399] The two types of NCAS identified by NEMMCO are described in those procedures as follows:

> **Reactive power ancillary service** [RPAS] is the capability to supply reactive power to, or absorb reactive power from, the transmission network in order to maintain the transmission network within its voltage and stability limits following a credible contingency event but excluding such capability within a transmission or distribution system or as a condition of connection.
>
> and
>
> **Network loading control ancillary service** [NLCAS] is the capability of reducing an active power flow from a transmission network in order to keep the [electrical] current loading on interconnector transmission elements within their respective ratings following a credible contingency event in a transmission network.

NEMMCO's choices in the procurement of NCAS are limited because of:

- clause 3.11.5(a) of the Rules, which states:

  "… NEMMCO must call for offers from persons who are in a position to provide the *non-market ancillary service* so as to have the required effect at a connection to a *transmission network* in an invitation to tender."

- clause 3.11.5(j) of the Rules, which states:

  "… NEMMCO must not acquire non-market ancillary services from any person who is not a Registered Participant."

- the RPAS description (noted above), which is qualified as:

  "excluding such capability within a transmission or distribution system"

thus excluding TNSPs from tendering for "residual" NCAS to NEMMCO.

[399] See http://www.nemmco.com.au/ancillary_services/168-0021.pdf.

Therefore, NEMMCO can only acquire NCAS from Registered Participants who are neither transmission NSPs nor distribution NSPs. The consequence is that provision of NCAS in the form of reactive power capability is in effect limited to:

- registered generators operating in generation mode;
- registered generators operating in SynCon mode; and
- MNSPs providing DC link voltage control.

Note that the costs of the services procured by NEMMCO as NCAS are recovered via a levy on all Market Customers in proportion to their energy use.

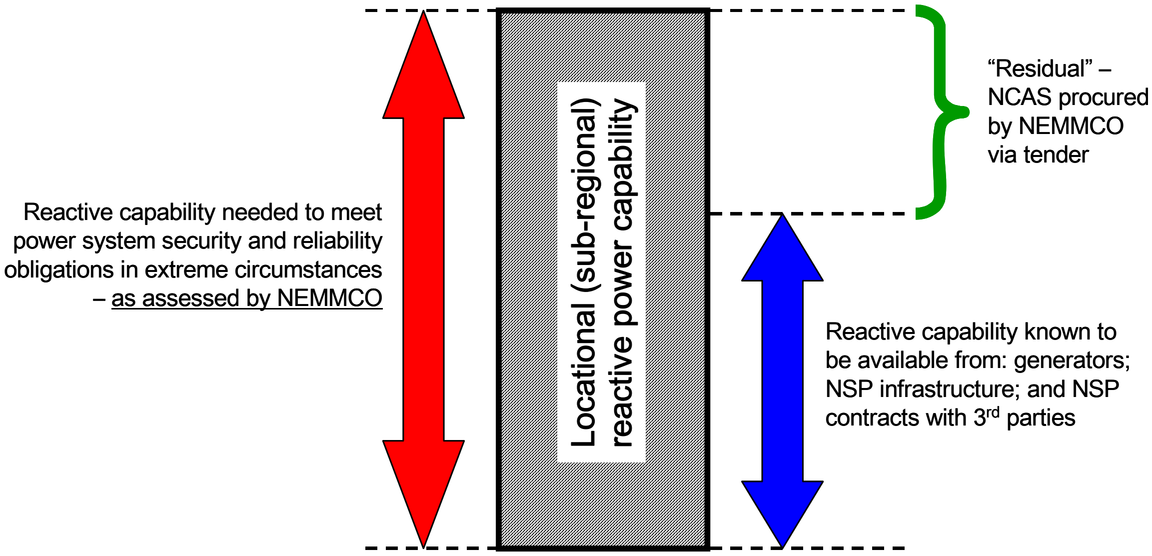
E.4.2.5 Determining the level of procurement

Power system security and reliability

NEMMCO's role in ensuring that appropriate levels of network support and control service are available to achieve the *power system security and reliability standards* may be seen as that of a "procurer of last resort"; in the absence of NEMMCO procurement of NCAS, the power system could experience either security or reliability problems.[400]

[400] NEMMCO anticipates the need for support & control services into the medium term. In the past, NEMMCO has contracted for NCAS on two-year time frames.

Figure E.8 Schematic representation of NEMMCO's reactive power capability procurement decision



With respect to NCAS in the form of reactive power capability, the volume procured by NEMMCO on a locational (sub-regional) basis is currently determined as the residual between (see Figure E.8):

- total capability required to manage power system security and reliability in either "peak loading conditions" or "low loading conditions";[401] and
- the capability guaranteed to be available through the combination of:
  - TNSPs (own infrastructure and contracts with third parties); and
  - generators delivering on performance standards specified in connection agreements between generators and TNSPs.

In making assessments as to the nature of the residual requirement, NEMMCO is therefore highly reliant on information provided to it by TNSPs.

[401] Peak loading conditions are normally associated with high summer and air-conditioning loads. Low loading conditions are those normally associated with overnight and/or weekend loads. For formal description of the reactive power requirement, see NEMMCO's *Amended procedure for determining quantities of network control ancillary services* [section 4.3, p.5], which can be found at http://www.nemmco.com.au/ancillary_services/168-0021.pdf.

Increasing the benefits of trade from the spot market

NEMMCO's obligations with respect to increasing the benefits of trade from the spot market are mentioned only in the (heavily qualified) Rule clause 3.11.4(b)(2), in which NEMMCO is required:

> where practicable to enhance *network* transfer capability whilst still maintaining a *secure operating state* when, in *NEMMCO's* reasonable opinion, the resultant expected increase in *non-market ancillary service* costs will not exceed the resultant expected increase in benefits of trade from the *spot market*.

The degree of qualification in this clause (underlined) gives a large amount of discretion to NEMMCO as to how the requirements of the clause are to be met.

NEMMCO has not yet conducted tenders for NCAS with the specific intent to procure services to increase the benefits of trade from the spot market. However, where NEMMCO has procured NCAS for the purpose of achieving the *power system security and reliability standards*, and those services can be deployed to increase the (net) benefits of trade from the spot market, NEMMCO will deploy NCAS for the (net) benefit of the market.

NEMMCO gives effect to clause 3.11.4(b)(2) by deploying both NLCAS and RPAS. Each of these services increases the secure (post-contingent) network capability of interconnectors and thus increases the ability of the dispatch process to replace high-cost generation in one region with low-cost generation from an adjoining region.

E.4.2.6 Stylised examples

The following examples outline the types of services that can be procured by either TNSPs or NEMMCO in fulfilling their respective NSCS obligations.

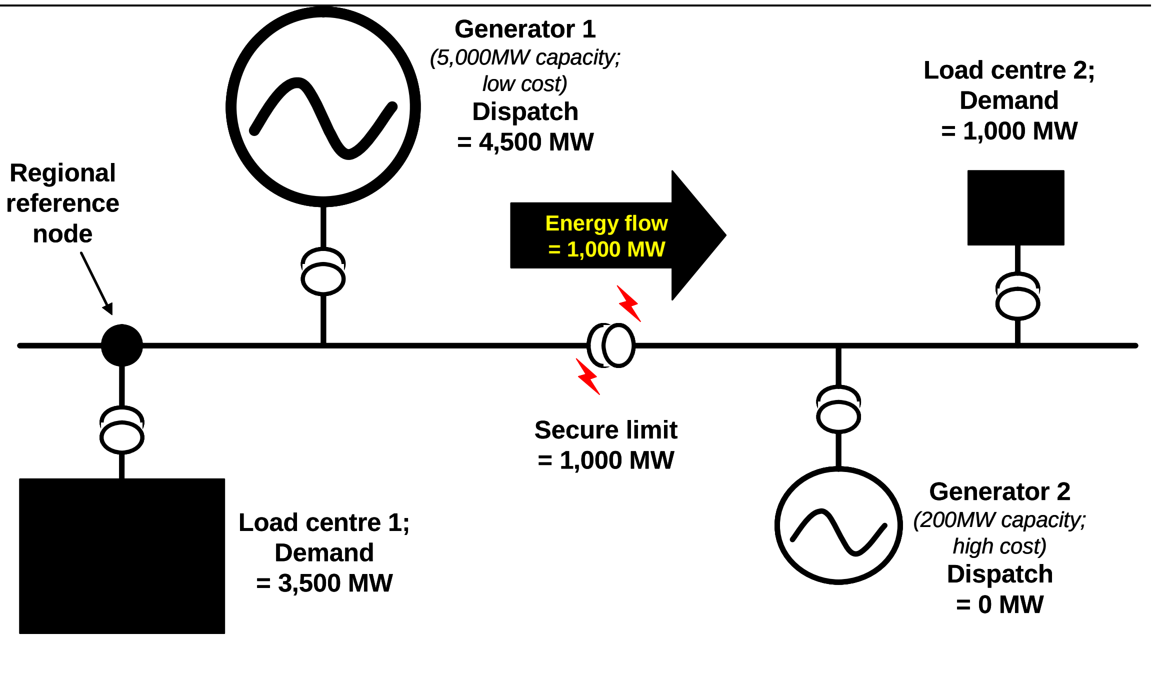
Constrained-on generation

This example illustrates the use of constrained-on generation as a mechanism to relieve loading on a critical transmission element.

- Power flow within the region depicted in Figure E.9 is constrained by a thermal limit on a transformer, such that flow is restricted to ≤ 1 000 MW from left to right. Demand and generation patterns within a region are initially such that low-cost Generator 1 is able to service all load within the region without network loading constraints being breached.
  - Total regional load is 4 500 MW [3 500 MW at Load centre 1; and 1 000 MW at Load centre 2].
  - Low-cost Generator 1 is dispatched at 4 500 MW and high-cost Generator 2 is not dispatched.

– Loading on the transformer subject to the constraint is at its secure limit of 1 000 MW.

Figure E.9 Initial network loading patterns—generation not constrained



- System conditions change, with a 200 MW increase in demand at each of Load centre 1 and Load centre 2. Total demand rises to 4 900 MW.

- In the absence of network constraints, total network loading is within the capability of low-cost Generator 1, but dispatch of 4 900 MW from Generator 1 (with no support from Generator 2) would breach the constraint on power flow through the transformer in the middle of the network by 200 MW. The choice is either to reduce demand (shed load) at Load centre 2 or dispatch Generator 2 to relieve the constraint on the transformer in the middle of the network.

- With network support available from Generator 2 (see Figure E.10):

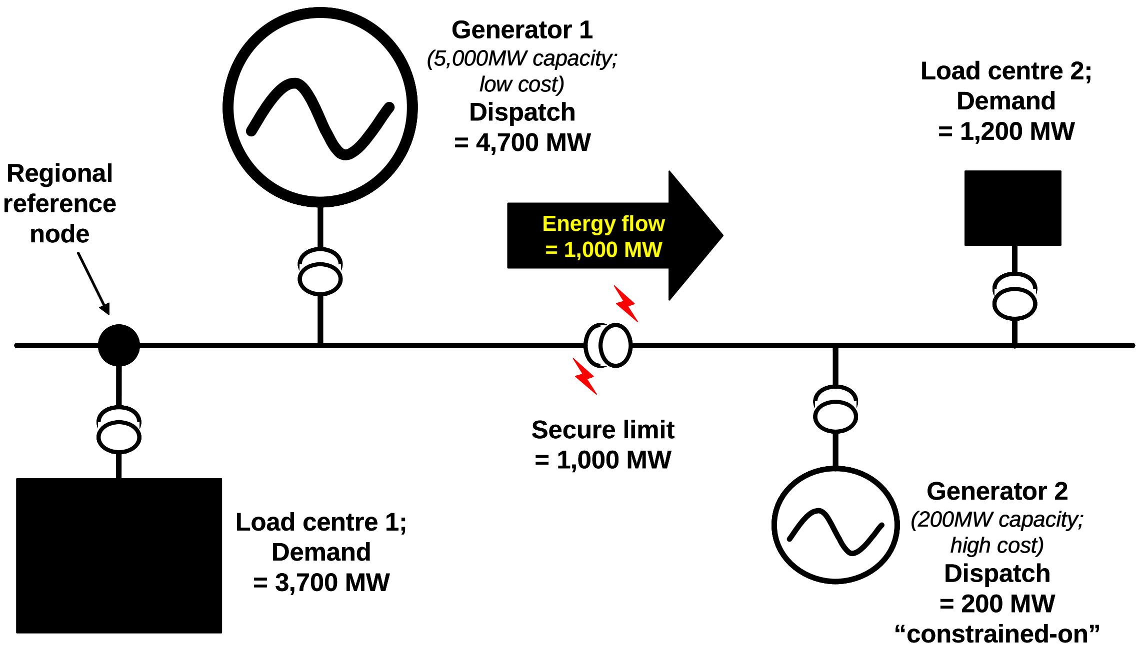
  – Total regional load is 4 900 MW (3 700 MW at Load centre 1, and 1 200 MW at Load centre 2).

  – Low-cost Generator 1 is dispatched at 4 700 MW and high-cost Generator 2 is dispatched at 200 MW.

  – Loading on the transformer subject to the constraint is at its secure limit of 1 000 MW.

As the RRP is established by the cost of meeting an increment of load at the regional RRN, the Generator 1 (low marginal cost) offer will set the price. If all generators are offering their output at marginal cost, Generator 2 (high marginal cost) will need to be constrained on. In the absence of some constrained-on payment (via a network support agreement or other mechanism), Generator 2 is likely to bid at or near VoLL or bid itself unavailable.

Figure E.10 Subsequent network loading patterns—generation constrained-on



Deployment of reactive power support (SynCons)

Figure E.11 illustrates the use of voltage support to increase power transfer capability. Although the example makes reference to transfers across region boundaries, it is equally applicable to circumstances where no region boundary is involved.

- In the absence of dynamic reactive power support, interconnector flow from Region A to Region B is limited to only 500 MW by voltage stability considerations. With reactive power support from G_{B3} operating in SynCon mode, interconnector flow from Region A to Region B can rise to 1 000 MW (see Figure 5).

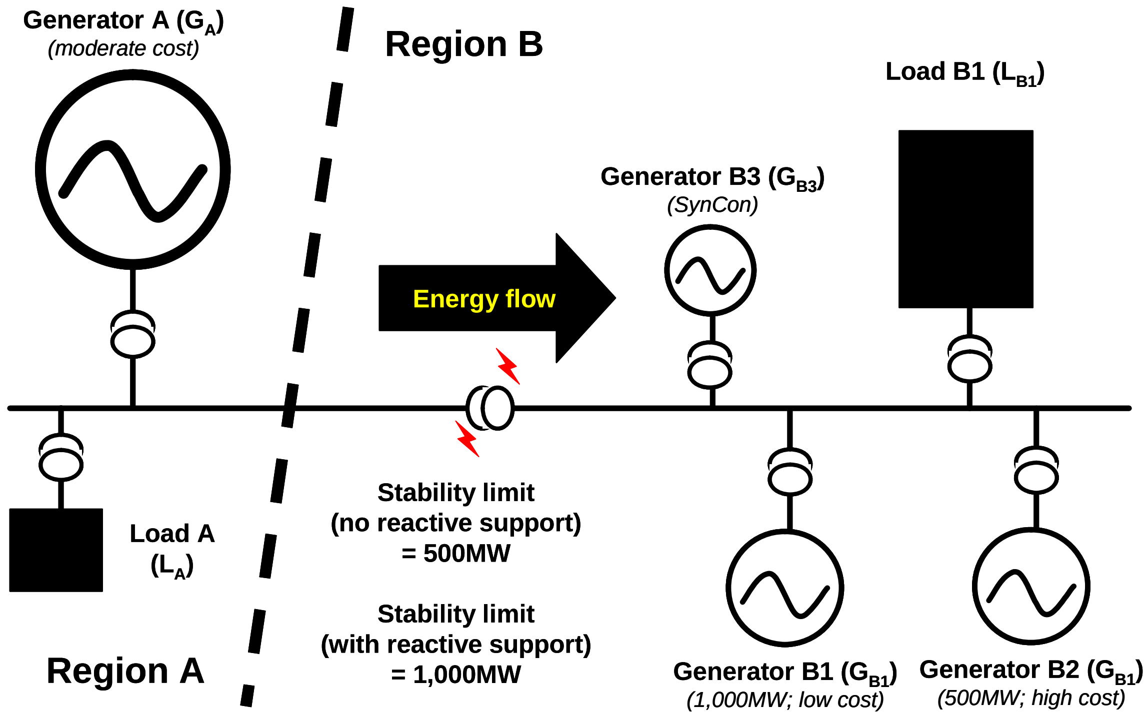
- If Region B load is 1 450 MW, optimal dispatch is 1 000 MW from (low cost) G_{B1} and 450 MW across the interconnector from Region A. There is no need to deploy reactive power support from G_{B3}.

- If Region B load rises beyond 1 500 MW, G_{B1} will be dispatched to its 1 000 MW limit and either:

– in the absence of reactive power support from G_{B3}, interconnector flow will be limited to 500 MW, with high-cost generator G_{B2} being dispatched to pick up the remaining supply deficit; or

– with reactive power support from G_{B3}, interconnector flow will be increased to (up to) 1 000 MW, with high-cost generator G_{B2} only being dispatched if Region B load rises beyond 2 000 MW. (This assumes generation from G_{B3} is high cost, but operating G_{B3} in SynCon mode is very low cost).

Figure E.11 Deploying SynCons to manage voltage stability limit



Deployment of load tripping scheme

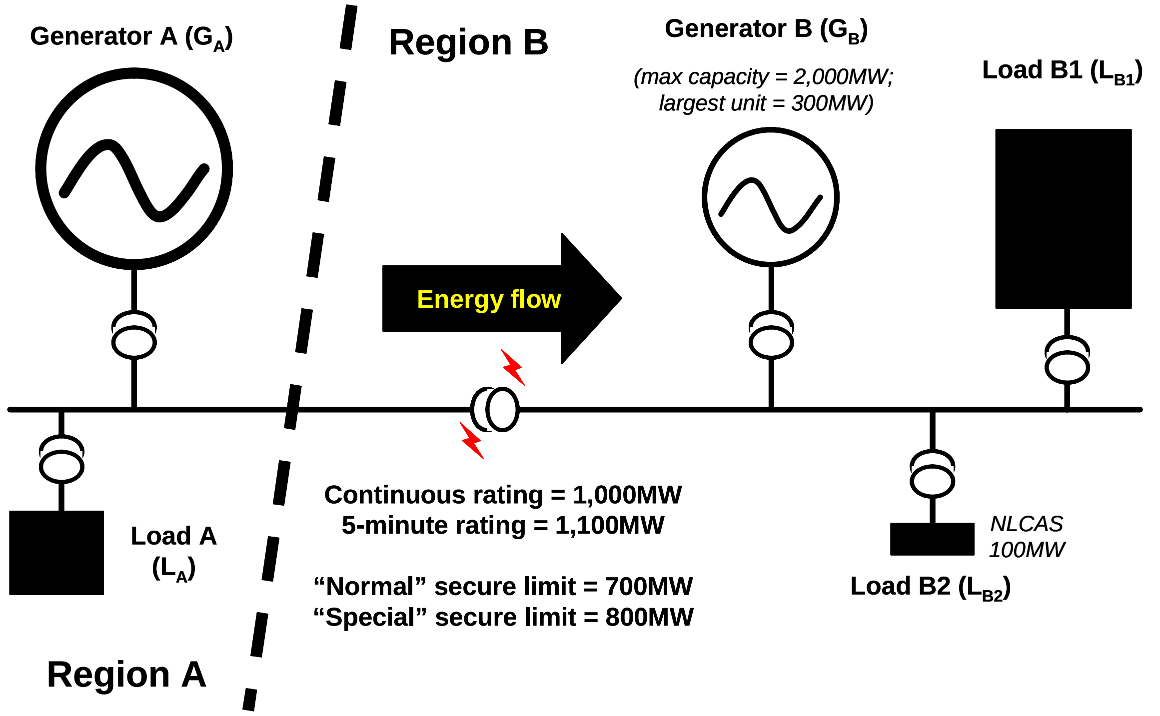
Figure E.12 illustrates the use of a load-tripping scheme, although the principles outlined may also be translated to rapid-response generators.

- Under "normal" conditions, local load (in Region B) of up to 2 700 MW can be securely and reliably managed—local generation GB of 2 000 MW plus interconnector transfer of up to 700 MW. The continuous rating of the interconnector flow from Region A to Region B is 1 000 MW (a thermal limit) but, in the absence of a suitable control scheme, it must be operated at a level such that the largest credible contingency (in this case, loss of 300 MW of Region B generation) does not push the transfer beyond its continuous rating. That is:

  secure limit (700 MW) = continuous rating (1 000 MW)
  – largest credible contingency (300 MW)

- If 100 MW load L_{B2} (e.g. a smelter) is associated with a control scheme that would trip it within 5 minutes of the post-contingent line flow reaching its 5-minute limit, and this scheme is procured by NEMMCO as a network loading control ancillary service (NLCAS), arming[402] the scheme enables the interconnector to securely operate at 800 MW, and thus (securely) service Region B load of up to 2 800 MW.

Figure E.12 Deploying load-tripping scheme to access 5-minute thermal ratings



If Region B load approaches 2 800 MW and the network loading control ancillary service at L_{B2} is armed, the higher "special" secure limit on interconnector flows of 800 MW could apply. This is because the occurrence of the largest single credible contingency (loss of a 300 MW generation unit) would result in the interconnector flow increasing up to 1 100 MW (its 5-minute rating) until such time as the control scheme operated by tripping the 100 MW of load at L_{B2} (sometime within 5 minutes). Tripping the 100 MW of load at L_{B2} would reduce Region B load back to 2 700 MW and interconnector flow to 1 000 MW (its continuous rating).[403]

[402] "Arming" the NLCAS involves preparing the load to trip in the event that flows on critical network elements move beyond their continuous rating – the design of the scheme is such that the load should remain "on" unless the relevant contingency occurs.

[403] If a contingency occurs and network elements exceed their secure operating limits, but stay within short-term ratings, the power system is declared to be in a satisfactory operating state and NEMMCO would have 30 minutes in which to return the power system to a secure operating state.

Note that generator control schemes—rapid unit loading or unloading—can be used to achieve similar outcomes to load-tripping schemes.

E.4.2.7 NEMMCO applications of support & control services

NEMMCO procures a network loading control service in the form of a smelter tripping scheme to access additional interconnector capability. It also procures reactive power capability in the form of Snowy generators operating in SynCon mode to manage voltage stability limits through the Snowy Region.

Under existing Rules, these services can be used either to:

- manage power system security or reliability [in accordance with clause 3.11.4(b)(1)]; or

- increase the benefits of trade from the spot market [in accordance with clause 3.11.4(b)(2)].

In order to increase the benefits of trade from the spot market, the cost of deploying the service should be less than the reduction in the total cost of generation dispatched in the market during the same period.

E.4.2.8 Summary

The current environment in which NSCS are delivered to the market is quite complex and contributes to a lack of clarity regarding the objectives for deploying NSCS. The environment can be described at a high level by matrixes that canvass several dimensions:

- **Responsibility:** “TNSPs” or “NEMMCO”;

- **Purpose:** “security & reliability” or “benefits of trade”;

- **Location:** “intra-regional” or “inter-regional”;

- **Application:** “voltage control” or “network loading control”; and

- **Technology:** capacitor banks, SVCs, reactive power from generators in SynCon mode, reactive power from generators in generation mode, pre-contingent DSM, post-contingent DSM.

Table E.2 and Table E.3 outline the relations between these dimensions.

Table E.2: Service responsibility by purpose and location

	Intra-regional	Inter-regional
Security & reliability	Both TNSPs and NEMMCO have responsibility for procuring / supplying NSCS.	No clear responsibilities formally assigned. Both TNSPs and NEMMCO procure / deliver services that have effect in this space.
Benefits of trade	Both TNSPs and NEMMCO have responsibility for procuring / supplying NSCS.	No services specifically procured for this purpose. Where practicable, NEMMCO deploys services procured for other reasons that have effect in this space.

Table E.3: Service technology by responsibility and application

	Reactive power capability	Network loading control
NEMMCO	Procured from generators in either SynCon or generation mode to: • manage power system stability in credible circumstances; and • increase secure transfer capability of selected network elements.	Procured in the form of load tripping schemes to increase the secure power transfer capability of selected network elements.
TNSPs	• Provided in the form of SVCs, capacitor banks and reactors to manage intra-regional reliability. • Secured from generators in generation mode as part of connection agreement.	Procured from generators and loads as network support to manage intra-regional reliability.

E.5 Positive Flow Clamping option

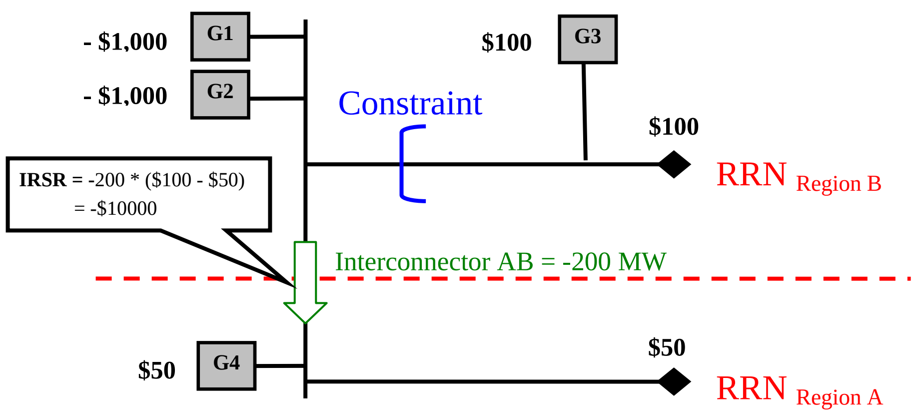
This section provides additional details on the concept of Positive Flow Clamping (PFC). In the Draft Report, we discussed PFC as an alternative to zero flow clamping (the current regime) as a way of managing negative residues under certain circumstances. While we are no longer pursing PFC as a viable alternative, it is informative to include a description of how it would work to provide context for the discussion in Appendix D where we present the reasoning for not accepting this option.

E.5.1 Description of PFC

Currently when NEMMCO forecasts that negative settlement residues between two regions will accumulate to a level of $6 000, NEMMCO reduces flow on the interconnector towards 0 MW until negative residue is no longer accumulating. In simple terms, the interconnector is clamped to 0 MW: zero flow clamping.

PFC represents an alternative response to the same set of conditions. Under PFC, NEMMCO still clamps the flow on the interconnector, but not to 0 MW; instead NEMMCO clamps it to some level of flow in the positively-priced direction (i.e. from low-priced region to high-priced region). As with the current regime, the PFC option would manage the accumulation of negative settlement residues. It could also make a greater contribution to the firmness of IRSR units by forcing the interconnector to flow in the positively-priced direction and thus to generate positive IRSR. In contrast, when zero flow clamping is invoked, no IRSR is generated to distribute to IRSR unit holders. This is illustrated in the example below (Figure E.13).

Figure E.13



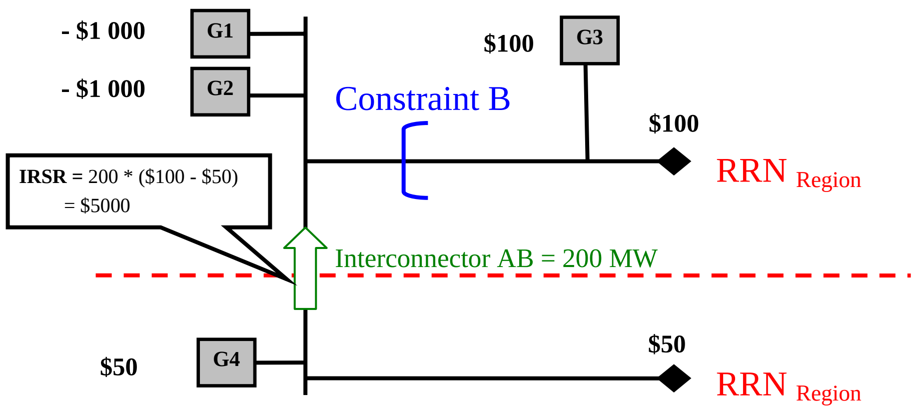
Constraint B prevents remote intra-regional generators G1 and G2 from setting the price in Region B. The price in Region B is set by local intra-regional generator G3. Generators G1 and G2 are thus able to bid below cost without affecting their settlement price. If they wish to generate at the RRP of $100, they might well enter very low bids to increase their chances of dispatch. At the extreme, they might bid -

$1 000. This could induce counter-priced flow on the interconnector. In the absence of intervention, negative residues would accumulate.

When the interconnector is clamped under the current regime to zero, neither positive nor negative residues accumulate. Although clamping to zero manages the issue of negative settlement residues, during the period of the clamping it renders the IRSR units useless as an inter-regional hedging instrument because zero IRSR is accumulating to distribute to IRSR unit holders. The financial impact of this situation is exacerbated if the regional price separation is high at the times when clamping is required.

PFC, will ensure that during intervention to manage negative residues, funds continue to flow to the IRSR fund by clamping the interconnector flow in the positively-priced direction. If we take the example discussed above, but this time clamp the interconnector to 200 MW in the positively-priced direction, there will be a positive accumulation of IRSR (see Figure E.14). Thus this option eliminates the negative residues, and generates positive residues to contribute to the firmness of the IRSR units. It does, however, mean that "cheaper" generation (based on the value of bids) is backed off to a greater extent.

Figure E.14



E.5.2 Implementation

PFC would be implemented by including additional discretionary constraint equations in dispatch. In practice, there is little difference between how the current clamping regime is implemented and how the PFC option would be implemented. Under the current clamping regime a constraint in the form of $I/C_{Flow} > 0$ is invoked when negative residues are identified. Under PFC a constraint in the form of $I/C_{Flow} > k$ would be invoked under similar circumstances, where k is some positive number (assuming that the positive flow direction is from the low-priced to high-priced region).

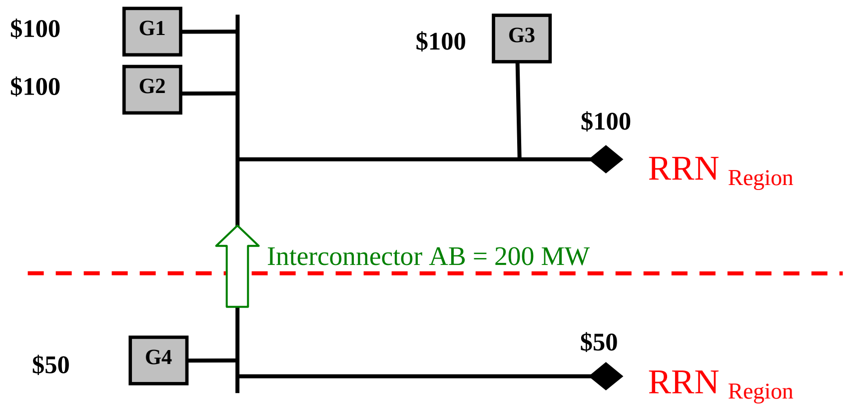
There are several approaches to establishing a value for k, as described below.

1. Dynamic *k*

Using this approach, *k* would be based on the actual dispatched flow on the interconnector just prior to PFC being invoked.

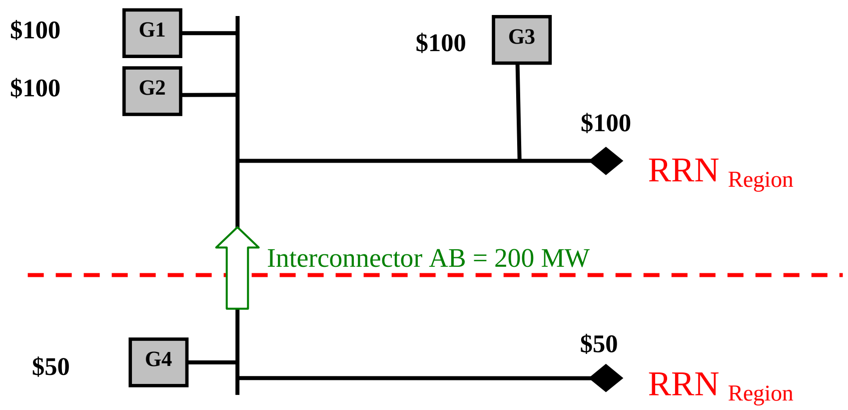
Consider the following example in which the interconnector is initially flowing in a positively-priced direction from Region A to Region B.

Figure E.15



Then, following the invocation on Constraint B, generators G1 and G2 are dislocated from the RRN and are thus incentivised to bid below cost to maximise dispatch.

Figure E.16

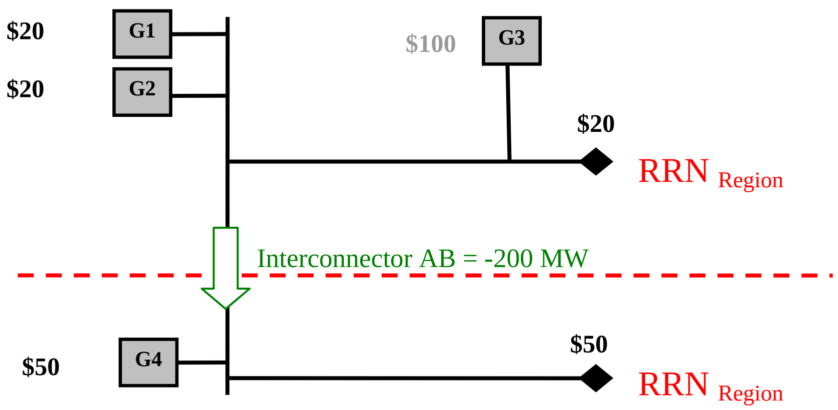


In the absence of intervention, G1 and G2 would force the interconnector to turn counter-price. As this is signalled through pre-dispatch, PFC would be invoked, clamping the interconnector at the pre-PFC flow of 200 MW.

This approach to establishing a value for *k* would, however, not be workable if counter-priced flow is established by a change in relative regional prices rather than a change in interconnector flow.

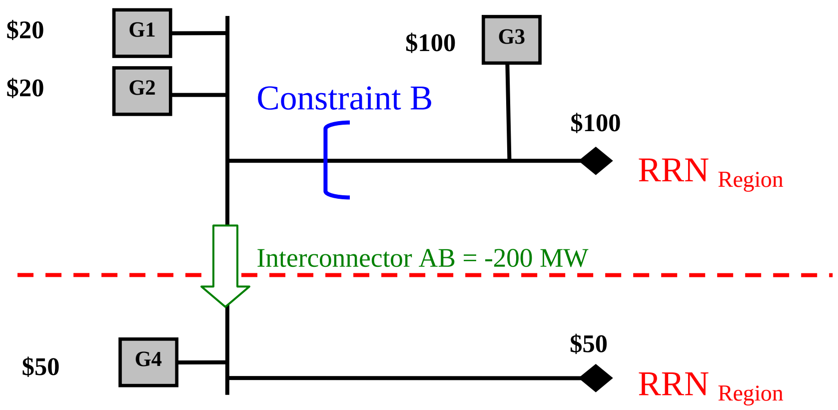
Consider the following example in which the interconnector is flowing in the positively-priced direction from Region B to Region A. G3 is not dispatched, and the price in Region B is set by G1 and G2.

Figure E.17



Following the invocation of Constraint B, G1 and G2 are backed off slightly and G3 is dispatched to meet load in Region B. G3 now sets the price in Region B at $100, and creates counter-priced flow.

Figure E.18



In this example, there is no pre-PFC interconnector flow in the positively-priced direction from which a value for *k* could be established. And in any case, it would be undesirable to clamp the interconnector in the positively-priced direction in this scenario. This would involve reversing the flow on the interconnector, which could require ramping up a large volume of generation in Region A and backing off a large volume of generation in Region B. This would be a major shift away from economic dispatch just prior to the invocation of Constraint B.

In this scenario, where the counter-priced flow was established by a change in relative regional prices rather than by a change in interconnector flow due to disorderly bidding, the interconnector could be (gradually) clamped to 0 MW to limit the effect on dispatch.

2. Static *k*

Using this approach, the value for *k* would be fixed at some level below the nominal capacity of the interconnector. The benefit of this approach is that it gives greater certainty as to the contribution to the IRSR fund at times when PFC is invoked. The difficulty of establishing a value for *k* remains, however. If *k* is set too low, PFC will make little contribution to firming IRSR units. If *k* is set too high, there is a risk that *k* could on occasions exceed the secure limit of the interconnector. Also compared to the approach of basing *k* on the pre-PFC dispatched interconnector flow, establishing a static value for *k* increases the risk of: (1) the price in the exporting region increasing to a level at which PFC itself creates counter-priced flow but in the opposite direction; and (2) requiring generators in the exporting region to be constrained-on to support the interconnector flow. These risks would be greatest on those occasions where *k* is significantly higher than the pre-PFC interconnector flow. For the reasons just outlined, this approach to setting *k* would need to be accompanied by a mechanism enabling the value of *k* to be reduced when necessary (which reduces the benefit of certainty with this approach).

3. Maximum capacity *k*

Using this approach, *k* would be set dynamically based on the maximum available capacity of the interconnector at the start of each dispatch interval. The benefit of this approach is that the value of the IRSR fund is maximised. The disadvantages are that constraining the interconnector to this level may represent a major shift from pre-PFC dispatch, which could raise issues regarding dispatch efficiency. As is the case with setting a static value for *k*, this approach also has a higher risk of creating counter-priced flow in the opposite direction and constraining-on generation.

Summary

The core differences between the three approaches are as follows:

- approach 1 aims to maintain dispatch as close as possible to the pre-PFC dispatch;
- approach 2 aims to maximise certainty by pre-defining the expected interconnector flow when PFC is invoked; and
- approach 3 aims to maximise the value of the IRSR by constraining-on the interconnector at its maximum physical capacity.

We considered approach 1 would distorts dispatch the least and was least likely to cause side effects (i.e. such as exceeding secure interconnector limits, inducing counter-priced flow, and constraining-on generation).

E.5.3 Trigger for invoking PFC

PFC could be triggered in various ways, including: (1) when negative residue is forecast, as is currently the case; or (2) when interconnector flow is first backed off by generators reducing their bids in response to dislocation from the RRN, regardless of the likelihood of negative residue. By invoking the measure when the interconnector is first backed off, the value of the IRSR would be maximised. However, this would represent a shift *from* intervention to manage negative residues and *to* intervention to influence dispatch results. It may also be difficult to identify reasons for change in interconnector dispatch. For these reasons PFC should be invoked based on a negative residue threshold.

The next question is what the negative residue threshold should be. Our recommendation in respect of zero flow clamping thresholds is that the negative residue threshold should be increased from $6 000 to $100 000.[404] This is based on the view that clamping creates uncertainty for Market Participants, which increases risk premiums and thus should be avoided or at least minimised. Since the sole purpose of zero flow clamping is to manage negative settlement residues, whereas PFC would also increase the firmness of IRSR units, it would seem contradictory to lengthen the period before PFC is invoked; this would have the effect of reducing the firmness of IRSR units. The threshold for PFC should remain at a level of $6 000.

E.5.3.1 Design overview

Based on the discussion above, we developed the following high-level design of PFC:

- PFC would be considered only for counter-priced flow events that are caused by generators' incentives to bid below cost due to their dislocation from the RRN. Such events would be pre-defined and identified by constraint equations.

- PFC would be invoked when negative residue caused by one of the defined constraints is forecast to accumulate to $6 000.

- Under PFC, the interconnector would be clamped to the flow at which that interconnector was dispatched in the dispatch interval just prior to the PFC invocation.

- If the interconnector turns counter-priced or was already flowing counter-priced prior to PFC being invoked, then the default arrangements for managing counter-priced flow (i.e. clamping to zero MW) would apply.

[404] See Chapter 3 of the Final Report or Appendix C, section C.2 for more information on this recommendation.

For the reasons discussed further in Appendix D, we are not proposing further development on PFC as an alternative to managing negative settlement residues, however.

This page has been intentionally left blank

F MCE Terms of Reference for this Review

This appendix provides a copy of the MCE's Terms of Reference for the Congestion Management Review.

MCE

Ministerial Council on Energy

CHAIR
The Hon Ian Macfarlane MP
Minister for Industry, Tourism and Resources
Telephone: (02) 6277 7580 Facsimile: (02) 6273 4104

Dr J Tamblyn
Chair
Australian Energy Market Commission
PO Box H166
AUSTRALIA SQUARE NSW 1215

- 5 OCT 2005

Dear ~~Dr Tamblyn~~ John

Pursuant to Part 4, Division 4 of the National Electricity Law, the Ministerial Council on Energy (MCE) by written notice, directs the Australian Energy Market Commission (AEMC) to consider the requirement for and scope of enhanced trading arrangements in relation to congestion management and pricing.

The MCE terms of reference provide guidance in three key areas.

- this review should identify and develop improved arrangements for managing financial and physical trading risks associated with material network congestion, with the objective of maximising the net economic benefit to all those who produce, consume and transport electricity in the market;
- the review should take account of, and clearly articulate, the relationship between a constraint management regime, constraint formulation, regional boundary review criteria and review triggers, the ANTS flow paths, the Last Resort Planning Power, the *regulatory test* and Transmission Network Service Provider incentive arrangements; and
- the constraint management regime should apply as a mechanism for managing material and enduring constraint issues, until it is addressed through investment or regional boundary change.

In conducting the review into congestion management regimes, the AEMC would benefit from having regard to

- the previous work undertaken by Charles River Associates on constraint management and pricing as part of their report, *NEM – Transmission Region Boundary Structure* (September 2004) and submissions to associated consultation; and
- the results emerging from the limited trial of Constraint Support Pricing/Constraint Support Contracting in the Snowy Region and an assessment of its broader impacts.

MCE Secretariat
GPO Box 9839 CANBERRA ACT 2601
Telephone: (02) 6213 7789 Facsimile: (02) 6213 7904
E-mail: MCE@industry.gov.au
Web Site: www.mce.gov.au

In light of the complexity of the review, the MCE requests that a final report be provided to the MCE, and made publicly available, no later than nine (9) months following receipt of these terms of reference.

The MCE provides terms of reference relevant to the Review at **Attachment A**. The MCE anticipates that the attached information will be posted on the AEMC website.
I trust this information is of assistance. Should you have any further enquiries, please contact Ms Loretta Boman of the Department of Energy on telephone 07 3225 8207.

Yours sincerely

Ian Macfarlane

Ian Macfarlane

ATTACHMENT A

National Electricity (South Australia) Act 1996

NATIONAL ELECTRICITY LAW

NOTICE OF REFERENCE UNDER PART 4, DIVISION 4

Terms of Reference for Australian Energy Market Commission

Congestion Management Review

1. BACKGROUND

1.1 The Ministerial Council on Energy (MCE) has recognised that no material efficiency benefits would be gained from a nodal pricing approach at this stage of market development. The MCE has endorsed a rule change to implement a regional boundary assessment process whereby new boundaries are created to price material and persistent network constraints with an emphasis on incremental and infrequent changes to the current boundaries. The MCE also endorses the consistent formulation of constraints using a form of constraint equation that allows the National Electricity market Management Company (NEMMCO) to control all variables (i.e. fully co-optimised direct physical representation).

1.2 The 20 May 2005 MCE Statement on NEM Electricity Transmission tasked the Australian Energy Market Commission (AEMC) to consider the requirement for and scope of enhanced trading arrangements in relation to congestion management and pricing, taking into account the results emerging from the Snowy trial and the Charles River Associates (CRA) study.

1.3 Pursuant to Part 4, Division 4 of the NEL (a Schedule set out under the *National Electricity (South Australia) Act 1996* (Act)), the MCE by written notice, may direct the AEMC to conduct a review into:

- any matter relating to the National Electricity Market; or
- the operation and effectiveness of the Rules; or
- any matter relating to the Rules.

1.4 Participating jurisdictions under the NEL are:

The Commonwealth;

The State of New South Wales;

The State of Victoria;

The State of Queensland;

The State of South Australia;

The Australian Capital Territory; and

The State of Tasmania,

and have agreed to the reference set out below.

2. REFERENCE

We, the MCE, by resolution dated XX September 2005, hereby direct the AEMC to review the matter described in section 3 of the Terms of Reference pursuant to Part 4, Division 4 of the NEL, in accordance with the Terms of Reference specified below.

3. TERMS OF REFERENCE

The following are the Terms of Reference for the review specified pursuant to section 41 of the NEL:

3.1 This review will identify and develop improved arrangements for managing financial and physical trading risks associated with material network congestion, with the objective of maximising the net economic benefit to all those who produce, consume and transport electricity in the market.

3.2 The AEMC review should take account of, and clearly articulate, the relationship between a constraint management regime; constraint formulation; regional boundary review criteria and review triggers; the ANTS flow paths; the Last Resort Planning Power; the Regulatory Test and TNSP incentive arrangements. The AEMC should develop a constraint management regime that applies as a mechanism for managing material constraint issues, until it is addressed through investment or regional boundary change.

3.3 The AEMC review on constraint management should have regard to the previous work undertaken by CRA on constraint management and pricing as part of their report NEM – Transmission Region Boundary Structure dated September 2004 and submissions to associated consultation should form the basis for the AEMC review on constraint management. In addition the results emerging from the limited trial of Constraint Support Pricing/Constraint Support Contracting in the Snowy Region and an assessment of its broader impacts should also be considered in this review. The AEMC should consult directly with NEMMCO on progress of the Snowy trial.

3.4 The Snowy trial is due to conclude in June 2007, and subject to the development of replacement arrangements that are found to benefit the market, there is an expectation that new arrangements will be implemented by this date.

3.5 On completion of the review, the AEMC will provide a report to the MCE, which will be made publicly available, outlining the AEMC's proposals in relation to the opportunities for enhanced constraint management arrangements. The AEMC must also provide draft Rule changes that would enable implementation of the proposed arrangements.

4. CONDUCT OF THE REVIEW

4.1 This review must be conducted in accordance with Part 4, Division 4 of the NEL.

4.2 The AEMC will provide a final report to the MCE, to be made publicly available, no later than 9 months following receipt of these terms of reference.

4.3 The AEMC must consult with industry and NEMMCO.

G Draft Rules

This appendix presents the Draft Rules that implement the recommendations in this Final Report. The Draft Rules are presented in the following order:

- Draft National Electricity Amendment (Fully Co-optimised and Alternative Constraint Formulations) Rule 2008.

- Draft National Electricity Amendment (Network Augmentations) Rule 2008.

- Draft National Electricity Amendment (Negative Inter-regional Settlements Residue Amounts) Rule 2008.

- Draft National Electricity Amendment (Congestion Information Resource) Rule 2008.

This page has been intentionally left blank

Exposure Draft National Electricity Amendment (Fully Co-optimised and Alternative Constraint Formulations) Rule 2008

under the National Electricity Law as applied by:

(a) the National Electricity (South Australia) Act 1996;
(b) the Electricity (National Scheme) Act 1997 of the Australian Capital Territory;
(c) the National Electricity (New South Wales) Act 1997 of New South Wales;
(d) the Electricity - National Scheme (Queensland) Act 1997 of Queensland;
(e) the Electricity - National Scheme (Tasmania) Act 1999 of Tasmania;
(f) the National Electricity (Victoria) Act 2005 of Victoria; and
(g) the Australian Energy Market Act 2004 of the Commonwealth.

The Australian Energy Market Commission makes the following Rule under the National Electricity Law.

John Tamblyn
Chairman
Australian Energy Market Commission

Draft National Electricity Amendment (Fully Co-optimised and Alternative Constraint Formulations) Rule 2008

1. Title of Rule

This Rule is the Draft National Electricity Amendment (Fully Co-optimised and Alternative constraint formulations) Rule 2008.

2. Commencement

This Rule commences operation on [insert date]

3. Amendment of National Electricity Rules

The National Electricity Rules are amended as set out in Schedule 1.

Schedule 1 Amendment of National Electricity Rules

[1] Chapter 8A, Part 8 Network Constraint Formulation, clause (a) [Deleted]

Omit Chapter 8A, Part 8, clause (a)

[2] Part 8, Chapter 8A, clause (b) [Deleted]

Omit Chapter 8A, Part 8, clause (b)

[3] Clause 3.8.1(b) Central Dispatch

Omit clause 3.8.1(b) and substitute:

(b) The *central dispatch* process should aim to maximise the value of *spot market* trading i.e. to maximise the value of *dispatched load* based on *dispatch bids* less the combined cost of *dispatched generation* based on *generation dispatch offers*, *dispatched network services* based on *network dispatch offers*, and *dispatched market ancillary services* based on *market ancillary service offers* subject to:

(1) *dispatch offers*, *dispatch bids* and *market ancillary service offers*;

(2) *constraints* due to availability and *commitment*;

(3) *non-scheduled load* requirements in each *region*;

(4) *power system security* requirements determined as described in Chapter 4 and the *power system security and reliability standards*;

(5) ~~*intra-regional*~~ *network constraints* ~~and *intra-regional losses*~~;

(6) *intra-regional* <u>*losses*</u> ~~*network constraints*~~ and *inter-regional losses*;

(7) *constraints* consistent with *registered bid and offer* data;

(8) current levels of *dispatched generation, load* and *market network services*;

(9) *constraints* imposed by *ancillary services* requirements;

(10) arrangements designed to ensure pro-rata loading of tied *registered bid and offer data*;

(11) ensuring that as far as reasonably practical, in relation to a *direction* or *dispatch* of *plant* under a *reserve contract*:

(A) the number of *Affected Participants* is minimised; and

(B) the effect on *interconnector flows* is minimized; and

(12) the management of negative *settlement residues*, in accordance with clause 3.8.10 and any guidelines issued by *NEMMCO* under clause 3.8.10(c).

[4] Clause 3.8.10 Network Constraints

Omit clause 3.8.10 and substitute:

(a) In accordance with the *NEMMCO power system security responsibilities* and any other standards set out in Chapter 4, *NEMMCO* must determine any *constraints* on the *dispatch* of *scheduled generating units, scheduled network services, scheduled loads, ancillary service generating units* or *ancillary service loads* which may result from planned *network outages*.

(b) Subject to clause 3.8.10(e), *NEMMCO* must determine and represent *network constraints* in *dispatch* which may result from limitations on both *intra-regional* and *inter-regional* power flows, and in doing so, must use a *fully co-optimised network constraint formulation*.

(c) *NEMMCO* must, in accordance with the *Rules consultation procedures*, develop, publish, and, where necessary, amend *network constraint* formulation guidelines, to address, amongst other things, the following matters:

(i) the circumstances in which *NEMMCO* will use *alternative network constraint formulations* in dispatch;

(ii) the process by which NEMMCO will identify or be advised of a requirement to create or modify a network constraint equation, including in respect of:

(1) the methodology to be used by *NEMMCO* in determining *network constraint* equation terms and co-efficients; and

(2) the means by which *NEMMCO* will obtain information from, and disseminate information to, *scheduled generators* and *market participants*;

(iii) the methodology to be used by *NEMMCO* in selecting the form of a *network constraint* equation, including in respect of the location of terms on each side of the equation;

(iv) the process to be used by *NEMMCO* for applying, invoking and revoking *network constraint* equations in respect of different types of *network constraints*, including in respect of:

(1) the circumstances in which *NEMMCO* will use *alternative network constraint formulations* and *fully co-optimised network constraint formulations; and*

(2) the dissemination of information to *scheduled generators* and *market participants* in respect of this process;

(v) *NEMMCO's* policy in respect of the management of negative *settlements residues*, by intervening in the dispatch process under clause 3.8.1 through the use of *fully co-optimised network* *constraint formulations*, including in respect of the process to be undertaken by *NEMMCO* to manage negative *settlements residue*.

(d) *NEMMCO* must at all times comply with the *network constraint* formulation guidelines issued in accordance with clause 3.8.10(c).

(e) Where, in *NEMMCO's* reasonable opinion, a specific *network constraint* is such that use of a *fully co-optimised network constraint formulation* is not appropriate, *NEMMCO* may apply an *alternative network constraint formulation* for the expected duration of that *network constraint*, if *NEMMCO*:

(i) has previously identified, in guidelines issued in accordance with clause 3.8.10(c), that it may use an *alternative network constraint formulation* in respect of that type of *network constraint*; and

(ii) reasonably considers that it can apply an *alternative network constraint formulation* without prejudicing its obligation to operate a *central dispatch* process to *dispatch scheduled generating units*, *scheduled loads*, *scheduled network services* and *market ancillary services* in order to balance *power system supply* and demand, consistent with using its reasonable endeavours to maintain *power system security* in accordance with Chapter 4 and to maximise the value of *spot market* trading on the basis of *dispatch offers* and *dispatch bids*, in accordance with clause 3.8.1(a) and (b).

(f) *NEMMCO* must represent *network constraints* as inputs to the *dispatch* process in a form that can be reviewed after the *trading interval* in which they occurred.

(g) Within 3 years of [X], which is the date the National Electricity Amendment (Fully Co-optimised and Alternative Constraint Formulation) Rule 2008 commences operation, the *AEMC* must commence a review in respect of the efficiency with which *NEMMCO* is managing circumstances in which the *settlements residue* arising in respect of a *trading interval* is a negative amount.

(h) In conducting a review in accordance with clause 3.8.10(g), the *AEMC* must have regard to the national electricity objective stated at section 7 of the *National Electricity Law*.

(i) The review under clause 3.8.10(g):

(i) may be conducted in such manner as the *AEMC* considers appropriate;

(ii) may (but need not) involve public hearings;

(j) During the course of the review conducted under clause 3.8.10(g), the *AEMC* may:

(i) consult with any person or body that it considers appropriate;

(ii) establish working groups to assist it in relation to any aspect, or matter or thing that is the subject of the review;

(iii) commission reports by other persons on its behalf on any aspect, or matter or thing that is the subject of the review;

(iv) publish discussion papers or draft reports.

(k) At the completion of the review conducted under clause 3.8.10(g), the *AEMC* must issue a report and give a copy of the report to the Ministerial Council on Energy.

~~(c) The process used by *NEMMCO* to derive the *network constraints* must be clearly documented and made available to *Scheduled Generators* and *Market Participants*.~~

[5] Clause 3.7.2(c)(3)

Omit clause 3.7.2(c)(3) and substitute:

(3) forecast ~~*inter-regional*~~ *network constraints* ~~and *intra-regional network constraints*~~ known to *NEMMCO* at the time.

[6] Clause 3.7.3(d)(3)

Omit clause 3.7.3(d)(3) and substitute:

(3) anticipated ~~*inter-regional network constraints* and *intra-regional*~~ *network constraints* known to *NEMMCO* at the time.

[7] Clause 3.9.7(a)

Omit clause 3.9.7(a) and substitute:

(a) In the event that a~~n *intra-regional*~~ *network constraint* causes a *scheduled generating unit* to be *constrained-on* in any *dispatch interval*, that *scheduled generating unit* must comply with *dispatch instructions* from *NEMMCO* in accordance with its availability as specified in its *dispatch offer* but may not be taken into account in the determination of the *dispatch price* in that *dispatch interval*.

[8] Clause 3.13.8(a)(5)

Omit clause 3.13.8(a)(5) and substitute:

(5) ~~*inter-regional* and *intra-regional*~~ *network constraints* by *trading interval*.

[9] Glossary

Insert the following new definitions:

alternative network constraint formulations

Any *network constraint* equation formulation used by *NEMMCO* other than a *fully co-optimised network constraint formulation*.

fully co-optimised network constraint formulation

A *network constraint* equation formulation that allows *NEMMCO*, through direct physical representation, to control all the variables that can be determined through the *central dispatch* process, within the equation.

Delete the following definitions:

~~**inter-regional network constraint**~~

~~A *constraint* on the *transmission* and/or *distribution networks* between *regions* as specified in clause 3.6.4(a).~~

~~**intra-regional network constraint**~~

~~A *constraint* on part of the *transmission* and *distribution networks* within a *region* as specified in clause 3.6.4(b)~~

Exposure Draft National Electricity Amendment (Network Augmentations) Rule 2008

under the National Electricity Law as applied by:

(a) the National Electricity (South Australia) Act 1996;
(b) the Electricity (National Scheme) Act 1997 of the Australian Capital Territory;
(c) the National Electricity (New South Wales) Act 1997 of New South Wales;
(d) the Electricity - National Scheme (Queensland) Act 1997 of Queensland;
(e) the Electricity - National Scheme (Tasmania) Act 1999 of Tasmania;
(f) the National Electricity (Victoria) Act 2005 of Victoria; and
(g) the Australian Energy Market Act 2004 of the Commonwealth.

The Australian Energy Market Commission makes the following Rule under the National Electricity Law.

John Tamblyn
Chairman
Australian Energy Market Commission

Draft National Electricity Amendment (Network Augmentations) Rule 2008

1. Title of Rule

This Rule is the Draft National Electricity Amendment (Network Augmentations) Rule 2008.

2. Commencement

This Rule commences operation on [insert date]

3. Amendment of National Electricity Rules

The National Electricity Rules are amended as set out in Schedule 1.

Schedule 1 Amendment of National Electricity Rules

[1] Clause 5.4A: Access arrangements relating to Transmission Networks

Omit clause 5.4A and substitute:

(a) The *Transmission Network Service Provider* referred to in this rule 5.4A is the *Transmission Network Service Provider* required under clause 5.3.3 to process and respond to a *connection* enquiry or required under clause 5.3.5 to prepare an offer to *connect* for the establishment or modification of a *connection* to the *transmission network* owned, controlled or operated by that *Transmission Network Service Provider* or for the provision of *network service*.

(b) If requested by a *Connection Applicant*, whether as part of a *connection* enquiry, application to *connect* or the subsequent negotiation of a *connection* agreement, the *Transmission Network Service Provider* must negotiate in good faith with the *Connection Applicant* to reach agreement in respect of the *transmission network user access* arrangements sought by the *Connection Applicant*.

(c) As a basis for negotiations under paragraph (b):

(1) the *Connection Applicant* must provide to the *Transmission Network Service Provider* such information as is reasonably requested relating to the expected operation of:

(i) its *generating units* (in the case of a *Generator*);

(ii) its *network elements* used in the provision of *network service* (in the case of a *Network Service Provider*); or

(iii) its *plant* (in the case of any other kind of *Connection Applicant*);

and

(2) the *Transmission Network Service Provider* must provide to the *Connection Applicant* such information as is reasonably

requested to allow the *Connection Applicant* to fully assess the commercial significance of the *transmission network user access* arrangements sought by the *Connection Applicant* and offered by the *Transmission Network Service Provider*.

(d) A *Connection Applicant* may seek *transmission network user access* arrangements at any level of *power transfer capability* between zero and:

(1) in the case of a *Generator*, the *maximum power input* of the relevant *generating units* or group of *generating units*;

(2) in the case of a *Network Service Provider*, the *power transfer capability* of the relevant *network elements*; and

(3) in the case of any other kind of *Connection Applicant*, the *maximum demand* at the *connection point* for the relevant *plant*.

(e) The *Transmission Network Service Provider* must use reasonable endeavours to provide the *transmission network user access* arrangements being sought by the *Connection Applicant* subject to those arrangements being consistent with *good electricity industry practice* considering:

(1) the *connection assets* to be provided by the *Transmission Network Service Provider* or otherwise at the *connection point*; and

(2) the potential *augmentations* or *extensions* required to be undertaken on all affected *transmission networks* or *distribution networks* to provide that level of *power transfer capability* over the period of the *connection agreement* taking into account the amount of *power transfer capability* provided to other *Registered Participants* under *transmission network user access* or *distribution network user access* arrangements in respect of all affected *transmission networks* and *distribution networks*.

(f) The *Transmission Network Service Provider* and the *Connection Applicant* must negotiate in good faith to reach agreement as appropriate on:

(1) the *connection service* charge to be paid by the *Connection Applicant* in relation to *connection assets* to be provided by the *Transmission Network Service Provider*;

(2) in the case of a *Market Network Service Provider*, the service level standards to which the *Market Network Service Provider* requires the *Transmission Network Service Provider* to adhere in providing it services;

(3) the *use of system services* charge to be paid:

(i) by the *Connection Applicant* in relation to any augmentations or extensions required to be undertaken on all affected transmission networks and distribution networks; and

(ii) where the *Connection Applicant* is a *Market Network Service Provider*, to the *Market Network Service Provider* in respect of any reduction in the long run marginal cost of *augmenting* the *transmission network* as a result of it being *connected* to the *transmission network*; ('*negotiated use of system charges*'); and

(4) the amounts ('*access charges*') referred to in paragraphs (g)-(j);

(5) where the connection applicant is a *Generator*, all negotiations between the *Transmission Network Service Provider* and the *Generator* must be conducted in a manner consistent with clause 6A.9.1.

(g) The amount to be paid by the *Connection Applicant* to the *Transmission Network Service Provider* in relation to the costs reasonably incurred by the provider in providing *transmission network user access*.

(h) Where the *Connection Applicant* is a *Generator*:

(1) the compensation to be provided by the *Transmission Network Service Provider* to the *Generator* in the event that the *generating units* or group of *generating units* of the *Generator* are *constrained off* or *constrained on* during a *trading interval*; and

(2) the compensation to be provided by the *Generator* to the *Transmission Network Service Provider* in the event that *dispatch* of the *Generator's generating units* or group of *generating units* causes another *Generator's generating units* or group of *generating units* to be *constrained off* or *constrained on* during a *trading interval*.

(i) Where the *Connection Applicant* is a *Market Network Service Provider:*

(1) the compensation to be provided by the *Transmission Network Service Provider* to the *Market Network Service Provider* in the event that the *transmission network user access* is not provided; and

(2) the compensation to be provided by the *Market Network Service Provider* to the *Transmission Network Service Provider* in the event that *dispatch* of the relevant *market network service* causes a *Generator's generating units* or group of *generating units* to be *constrained off* or *constrained on* during a *trading interval* or causes the *dispatch* of another *market network service* to be *constrained*.

(j) In the case of any other kind of *Connection Applicant*, the compensation to be provided by the *Transmission Network Service Provider* to the *Connection Applicant* in the event that the *transmission network user access* is not provided.

(k) The maximum charge that can be applied by the *Transmission Network Service Provider* in respect of *negotiated use of system* *charges* for the *transmission network* is a charge that is determined in accordance with Part J of Chapter 6A.

[2] Clause 6A.9.1: Principles relating to access to negotiated transmission services

Omit clause 6A.9.1 and substitute:

The following principles constitute the *Negotiated Transmission Services Principles*:

(1) the price for a *negotiated transmission service* should be based on the costs incurred in providing that service, determined in accordance with the principles and policies set out in the *Cost Allocation Methodology* for the relevant *Transmission Network Service Provider*;

(2) subject to subparagraphs (3) and (4), the price for a *negotiated transmission service* should be at least equal to the avoided cost of providing it but no more than the cost of providing it on a stand alone basis;

(3) if the *negotiated transmission service* is the provision of a *shared transmission service* that:

(i) exceeds the network performance requirements (if any) which that *shared transmission service* is required to meet under any *jurisdictional electricity legislation*; or

(ii) exceeds the *network* performance requirements set out in schedules 5.1a and 5.1, then the differential between the price for that service and the price for the *shared transmission service* which meets (but does not exceed) the *network* performance requirements under any *jurisdictional electricity legislation* or as set out in schedules 5.1a and 5.1 (as the case may be) should reflect the increase in the *Transmission Network Service Provider's* incremental cost of providing that service;

(4) if the *negotiated transmission service* is the provision of a *shared transmission service* that does not meet (and does not

exceed) the *network* performance requirements set out in schedules 5.1a and 5.1, the differential between the price for that service and the price for the *shared transmission service* which meets (but does not exceed) the *network* performance requirements set out in schedules 5.1a and 5.1 should reflect the amount of the *Transmission Network Service*

Provider's avoided cost of providing that service;

(5) the price for a *negotiated transmission service* must be the same for all *Transmission Network User*s unless there is a material difference in the costs of providing the *negotiated transmission service* to different *Transmission Network User*s or classes of *Transmission Network User*s;

(6) the price for a *negotiated transmission service* should be subject to adjustment over time to the extent that the assets used to provide that service are subsequently used to provide services to another person, in which case such adjustment should reflect the extent to which the costs of that asset is being recovered through charges to that other person;

<u>*Note: An adjustment as referred to in subparagraph (6) may, for example, be appropriate where the cost of providing the negotiated transmission service to a Service Applicant changes because the assets used to provide that service are subsequently used to provide a service to another person and the payment for the service by that other person enables the Transmission Network Service Provider to recoup some of those costs from that other person.*</u>

(7) the price for a *negotiated transmission service* should be such as to enable the *Transmission Network Service Provider* to recover the efficient costs of complying with all *regulatory obligations or requirements* associated with the provision of the *negotiated transmission service*;

(8) any *access charges* should be based on the costs reasonably incurred by the *Transmission Network Service Provider* in providing *transmission network user access* and (in the case of compensation referred to in rules 5.4A(h) - (j)) on the revenue that is likely to be foregone and the costs that are likely to be incurred by a person referred to in rule 5.4A(h)-(j) where an event referred to in those paragraphs occurs;

(9) the *terms and conditions of access* for a *negotiated transmission service* should be fair and reasonable and consistent with the safe and *reliable* operation of the *power system* in accordance with the *Rules* (for these purposes, the price for a *negotiated transmission service* is to be treated as being fair and reasonable if it complies with principles (1) to (7) of this clause 6A.9.1);

(10) the *terms and conditions of access* for a *negotiated transmission service* (including, in particular, any exclusions and limitations of liability and indemnities) must not be unreasonably onerous taking into account the allocation of risk between the *Transmission Network Service Provider* and the other party, the price for the *negotiated transmission service* and the costs to the *Transmission Network Service Provider* of providing the *negotiated transmission service*; and

(11) the *terms and conditions of access* for a *negotiated transmission service* should take into account the need for the service to be provided in a manner that does not adversely affect the safe and *reliable* operation of the *power system* in accordance with the *Rules*.

Exposure Draft National Electricity Amendment (Negative Inter-regional Settlements Residue Amounts) Rule 2008

under the National Electricity Law as applied by:

(a) the National Electricity (South Australia) Act 1996;
(b) the Electricity (National Scheme) Act 1997 of the Australian Capital Territory;
(c) the National Electricity (New South Wales) Act 1997 of New South Wales;
(d) the Electricity - National Scheme (Queensland) Act 1997 of Queensland;
(e) the Electricity - National Scheme (Tasmania) Act 1999 of Tasmania;
(f) the National Electricity (Victoria) Act 2005 of Victoria; and
(g) the Australian Energy Market Act 2004 of the Commonwealth.

The Australian Energy Market Commission makes the following Rule under the National Electricity Law.

John Tamblyn
Chairman
Australian Energy Market Commission

Draft National Electricity Amendment (Negative Inter-regional Settlements Residue Amounts) Rule 2008

1. Title of Rule

This Rule is the Draft National Electricity Amendment (Negative Inter-regional Settlements Residue Amounts) Rule 2008.

2. Commencement

This Rule commences operation on [insert date]

3. Amendment of National Electricity Rules

The National Electricity Rules are amended as set out in Schedule 1.

Schedule 1 Amendment of National Electricity Rules

[1] Rule 3.6.5(4) Settlements residue due to network losses and constraints

Omit rule 3.6.5 and substitute:

(a) *Settlements residue* will be allocated, and distributed or recovered by *NEMMCO* in accordance with the following principles:

(1) full effect is to be given to the *jurisdictional derogations* contained in Chapter 9 relating to *settlements residue*;

(2) the portion of the *settlements residue* attributable to *regulated interconnectors* (as adjusted to take into account the effect of any applicable *jurisdictional derogations* referred to in clause 3.6.5(a)(1)) will be distributed or recovered in accordance with rule 3.18;

(3) the remaining *settlements residue*, including the portion of *settlements residue* due to *intra-regional loss factors,* will be distributed to or recovered from the appropriate *Transmission Network Service Providers* (which will not include *Market Network Service Providers*);

(4) subject to clauses 11.1.1 and 11.1.2, if the *settlements residue* arising in respect of a *trading interval*, after taking into account any adjustment in accordance with clauses 5.7.7(aa)(3) or (ab), is a negative amount, then, in respect of each *billing period* in which a negative *settlements residue* arises:

(i) *NEMMCO* must recover the amount from the appropriate *Transmission Network Service Provider* (which will not include *Market Network Service Providers*) within the *region* (the "importing region") to which electricity is transferred from another *region* (the "exporting region") through *regulated interconnectors*, at a payment interval, and by a method, to be determined by *NEMMCO*, and which may include a determination that an appropriate *Transmission Network Service Provider* make payment at a date prior to the settlement date determined in respect of other *Transmission Network Service Providers*; and

(ii) the appropriate *Transmission Network Service Provider* (which will not include *Market Network Service Providers*) must make the payment at the time, payment interval and by the method determined by *NEMMCO*.

(4A) subject to clauses 3.6.5(a)(4), 11.1.1 and 11.1.2, where interest costs are incurred by *NEMMCO* in relation to any unrecovered negative *settlements residue* amounts referred to in clause 3.6.5(a)(4), in respect of each *billing period* in which a negative *settlements residue* arises:

(i) *NEMMCO* must recover the interest costs from the appropriate *Transmission Network Service Provider* (which will not include *Market Network Service Providers*) within the *region* (the "importing region") to which electricity is transferred from another *region* (the "exporting region") through *regulated interconnectors*, at a payment interval, and by a method, to be determined by *NEMMCO*, and which may include a determination that an appropriate *Transmission Network Service Provider* make payment at a date prior to the settlement date determined in respect of other *Transmission Network Service Providers*; and

(ii) the appropriate *Transmission Network Service Provider* (which will not include *Market Network Service Providers*) must make the payment at the time, payment interval and by the method determined by *NEMMCO*.

(4B) for the purposes of clauses 3.6.5(4) and 3.6.5(4A), the AER must, in accordance with the *Rules consultation procedures*, make, *publish*, and where necessary, amend, a determination identifying the appropriate *Transmission Network Service Provider* (which will not include *Market Network Service Providers*) responsible for payments in respect of a *negative settlements residue*, in relation to each directional *interconnector*, and must notify *NEMMCO* of the making or amendment of any such determination.

(5) for the purposes of the distribution or recovery of *settlements residue* that is attributable to *regulated interconnectors*:

(i) all of the *settlements residue* relating to electricity that is transferred from one *region* (the "exporting region") to another *region* (the "importing region") must be allocated to *Network Service Providers* in respect of a *network* located in the importing region (or part of a *network* located in the importing region);

(ii) the importing region must, in respect of the period from *market commencement* until the expiry date referred to in subparagraph (iv), pay a charge to the exporting region reflecting the extent of the use of a *network* located in the exporting region (or part of a *network* located in the exporting region) to transfer the electricity from the exporting region to the importing region;

(iii) the amount of the charge described in subparagraph (ii) must not exceed the amount of the *settlements residue* referred to in subparagraph (i), and must be agreed between the *participating jurisdictions* in which the importing region and the exporting region are located; and

(iv) the expiry date referred to in subparagraph (ii), means 1 July 2009 or the date of commencement of rules which make alternative provision in the *Rules* for inter-regional *settlements*, whichever is the earlier date; and

(6) any portion of *settlements residue* distributed to a *Network Service Provider* or amount paid on that portion under clause 3.15.10A (if any), or rule 3.18 to a *Network Service Provider*, including any such payments as adjusted by a *routine revised statement* or *special revised statement* issued under rule 3.15, net of any portion of *settlements residue* recovered from the *Network Service Provider* in accordance with clause 3.6.5(a)(4), will be used to offset *network service* charges.

(b) A *Transmission Network Service Provider* or its jurisdictional delegate is a *Market Participant* for the purposes of clause 3.3.1 and rule 3.15 (excluding clause 3.15.1(b)) but not otherwise.

~~(c) Subject to clauses 11.1.1 and 11.1.2:~~

~~(i) clause 3.6.5(a)(4) does not have effect during the period commencing on 1 July 2006 and ending at the last moment of 30 June 2009 but comes into effect again at the end of that period; and~~

~~(ii) clauses 3.6.5(a)(4A) and (4B) expire at the end of that period~~.

[2] Rule 3.15.1 Settlement Management by *NEMMCO*

Omit rule 3.15.1 and substitute:

(a) *NEMMCO* must facilitate the billing and settlement of payments due in respect of *transactions* under this Chapter 3, including:

(1) *spot market allocations*;

(2) *reallocation transactions*;

(3) negative *settlement residues* under clause 3.6.5; and

(4) ancillary services transactions under clause 3.15.6A.

(b) *NEMMCO* must determine the *Participant Fees* and the *Market Participants* must pay them to *NEMMCO* in accordance with clause 3.15.6A.

[3] Rule 3.18.4 Proceeds and fees

Omit rule 3.18.4 and substitute:

(a) *NEMMCO* must distribute:

(1) subject to clauses 3.6.5(a)(4) and (4A), proceeds from each *auction* in respect of a *directional interconnector*; and

(2) subject to clauses 3.18.4(b) and (c), any portion of the *settlements residue* allocated to the *directional interconnector* which is not the subject of a *SRD agreement*, to the appropriate *Network Service Providers* in accordance with the principles referred to in clause 3.6.5 in relation to the allocation and distribution of *settlements residue* attributable to *regulated interconnectors*.

(b) The costs and expenses incurred by *NEMMCO* in establishing and administering the arrangements contemplated by this rule 3.18, in conducting *auctions* under this rule 3.18 and in entering into and administering *auction participation agreements* and *SRD agreements* under this rule 3.18 will be recovered from *settlements residue* by way of *auction expense fees*.

(c) The *auction expense fees* are to be developed by *NEMMCO* in accordance with the *auction rules* and approved by the *settlement residue committee*, and recovered as follows:

(1) to the extent the *settlements residue* is distributed to *eligible persons* under clause 3.18.1(d), in accordance with the *auction rules*; and

(2) to the extent the *settlements residue* is distributed to *Network Service Providers* under clause 3.18.4(a)(2), as if the *settlements residue* was being distributed to *eligible persons* in accordance with the *auction rules*.

(d) The *auction expense fees* for an *auction* are to be *published* before the *auction*.

(e) *Eligible persons* and *NEMMCO* must pay *auction amounts* in accordance with the *auction rules*, and, for the avoidance of doubt, amounts payable by *eligible persons* to *NEMMCO* under *SRD agreements* will not be regarded as amounts payable under the *Rules* for the purposes of rule 3.15.

(f) *NEMMCO* may nominate an electronic funds transfer facility for the purposes of paying *auction amounts* and, if it does so, *eligible persons*, *Network Service Providers* and *NEMMCO* must use that facility for paying and receiving a*uction amounts*.

[3] Rule 11.1 Rules consequent on making of the National Electricity Amendment (Negative Inter-Regional Settlements Residue) Rule 2006

Omit rule 11.1.1 and substitute:

11.1 Rules consequent on making of the National Electricity Amendment (Negative Inter-regional Settlements Residue Amounts) Rule 2008

11.1.1 Recovery of accrued negative settlements residue

<u>Clause 3.6.5(a)(4A), as in force immediately before [*X*] which is the date the National Electricity Amendment (Negative Inter-Regional Settlements Residue Amounts) Rule 2008 commences operation, continues to apply to any negative *settlements residue* amounts arising before [*X*] and not recovered as at [*X*] until all such negative amounts have been recovered.</u>

~~(b) Where negative *settlements residue* amounts arise on or after 1 July 2005 and are not recovered before 1 July 2006 which is the date the~~

~~National Electricity Amendment (Negative Inter-Regional Settlements Residue) Rule 2006 commences operation, then:~~

~~(i) the whole or any part of the amount may be recovered from the proceeds of the first *auction* after 1 July 2006 which is the date the National Electricity Amendment (Negative Inter-Regional Settlements Residue) Rule 2006 commences operation; and~~

~~(ii) if the whole or a part of the amount is not recoverable under clause 11.1.1(b)(i), the unrecovered amount may be recovered from the proceeds of successive *auctions* until the negative amount is recovered.~~

~~(c) Clause 3.6.5(a)(4A), as in force immediately before 30 June 2009, continues to apply to any *negative settlements* residue amounts arising on or after 1 July 2006 but before 30 June 2009, and not recovered as at 30 June 2009, until all such negative amounts have been recovered.~~

[4] Rule 11.1.2 Recovery of interest costs associated with accrued negative settlements residue

Omit rule 11.1.2 and substitute:

(a) Where interest costs incurred by *NEMMCO* in relation to any unrecovered negative *settlements residue* amounts referred to in clause 3.6.5(a)(4A) (as in force immediately before [*X*] which is the date the National Electricity Amendment (Negative Inter-Regional Settlements Residue Amounts) Rule 2008 commences operation) before [*X*] are not recovered before [*X*] which is the date the National Electricity Amendment (Negative Inter-regional Settlements Residue Amounts) Rule 2008 commences operation, then:

(i) the whole or any part of the interest costs may be recovered from the proceeds of the first *auction* after [*X*] which is the date National Electricity Amendment (Negative Inter-regional Settlements Residue Amounts) Rule 2008 commences operation:

(ii) if the whole or a part of the interest costs are not recoverable under clause 11.1.2(a)(i), the unrecovered interest costs may be recovered from the proceeds of successive *auctions* until the interest costs are recovered.

(b) Clause 3.6.5(a)(4B), as in force immediately before [X] which is the date the National Electricity Amendment (Negative Inter-Regional Settlements Residue Amounts) Rule 2008 commences operation, continues to apply to any interest costs arising before [X], and not recovered as at [X], until all such interest costs have been recovered.

Exposure Draft National Electricity Amendment (Congestion Information Resource) Rule 2008

under the National Electricity Law as applied by:

(a) the National Electricity (South Australia) Act 1996;
(b) the Electricity (National Scheme) Act 1997 of the Australian Capital Territory;
(c) the National Electricity (New South Wales) Act 1997 of New South Wales;
(d) the Electricity - National Scheme (Queensland) Act 1997 of Queensland;
(e) the Electricity - National Scheme (Tasmania) Act 1999 of Tasmania;
(f) the National Electricity (Victoria) Act 2005 of Victoria; and
(g) the Australian Energy Market Act 2004 of the Commonwealth.

The Australian Energy Market Commission makes the following Rule under the National Electricity Law.

John Tamblyn
Chairman
Australian Energy Market Commission

Exposure Draft National Electricity Amendment (Congestion Information Resource) Rule 2008

1. Title of Rule

This Rule is the *Exposure Draft National Electricity Amendment (Congestion Information Resource) Rule 2008.*

2. Commencement

This Rule commences operation on [insert date].

3. Amendment of the National Electricity Rules

The National Electricity Rules are amended as set out in Schedule 1.

Schedule 1 Amendment of National Electricity Rules

[1] Rule 3.7A Market information on planned network outages

Omit rule 3.7A and substitute:

3.7A Congestion information resource

(a) The objective of the *congestion information resource* is to provide information in a cost effective manner to *Market Participants* to enable them to understand patterns of *network* congestion and make projections of *market* outcomes in the presence of *network* congestion ('the *congestion information resource objective'*).

Development of congestion information resource

(b) To implement the *congestion information resource objective*, *NEMMCO* must develop and *publish*, in accordance with this rule 3.7A, an information resource comprising:

(1) information on *planned network events*; and

(2) information on the incidence of congestion in the *National Electricity Market* through the use of historical data on *mis-pricing* at *transmission network* nodes in the *National Electricity Market*; and

(3) any other information that *NEMMCO*, in its reasonable opinion, considers relevant to implement the *congestion information resource objective*,

which is to be known as the *congestion information resource*.

(c) The *congestion information resource* must contain at least the same level of detail as is required to be included in the interim *congestion information resource* published under clause 11.X.2(b).

(d) *NEMMCO* must develop, and amend from time to time, the *congestion information resource*:

(1) consistently with the *congestion information resource objective*;

(2) in accordance with the *congestion information resource guidelines*; and

(3) to incorporate any new, or amend any existing, aspect of the *congestion information resource* where *NEMMCO* forms the view that such an amendment will improve the *congestion information resource's* implementation of the *congestion information resource objective*.

(e) Subject to paragraph (f), *NEMMCO* must update and *publish* the information contained in the *congestion information resource* (whether in whole or in part) at intervals to be determined by *NEMMCO* in accordance with the *congestion information resource guidelines*.

(f) The intervals determined by *NEMMCO* for updating and *publishing* the *congestion information resource* must be included in the *timetable*.

(g) Where there has been a material change in the facts or circumstances described in the *congestion information resource* and *NEMMCO* considers *Market Participants* require the new information prior to the next periodic update of the *congestion information resource* in accordance with paragraph (e), *NEMMCO* may provide *Market Participants* with the new information in accordance with the *congestion information resource guidelines*.

(h) *NEMMCO* must publish the first *congestion information resource* by [DATE B] and there must be a *congestion information resource* available at all times after that date.

Note: DATE B is intended to be 1 year after this Rule commences operation.

(i) For the purpose of *publishing* the first *congestion information resource* under paragraph (b), *NEMMCO* may, subject to paragraph (d), *publish* the interim congestion information resource referred to in clause 11.X.2, as the first *congestion information resource*, in whole or in part.

(j) *NEMMCO* must not *publish confidential information* as part of, or in connection with, the *congestion information resource*.

Congestion information resource guidelines

(k) *NEMMCO* must develop and *publish* guidelines ('the *congestion information resource guidelines*') for and with respect to:

(1) the categories of information to be contained in the *congestion information resource* including the source of that information;

(2) the scope and type of the information to be provided by *Transmission Network Service Providers* in accordance with paragraphs (n) and (o);

(3) the processes to be implemented by *NEMMCO* to obtain the information from *Transmission Network Service Providers* in accordance with paragraphs (n) and (o);

(4) the determination of the intervals for updating and *publishing* the *congestion information resource* under paragraph (e); and

(5) the processes to be implemented by *NEMMCO* for providing *Market Participants* with information under paragraph (g).

(l) *NEMMCO* must develop and *publish* the first *congestion information resource guidelines* in accordance with the *Rules consultation procedures* by [DATE A] and there must be a set of *congestion information resource guidelines* available and up to date at all times after this date.

Note: DATE A is intended to be 6 months after this Rule commences operation.

(m) *NEMMCO* must amend the *congestion information resource guidelines* in accordance with the *Rules consultation procedures*.

Information of Transmission Network Service Providers

(n) In addition to the obligations imposed on *Transmission Network Service Providers* by rule 3.7, *Transmission Network Service Providers* must provide *NEMMCO* with the information specified in the *congestion information resource guidelines*:

(1) in a form which clearly identifies *confidential information*; and

(2) in accordance with the *congestion information resource guidelines*.

(o) Where there has been a material change in the information provided by a *Transmission Network Service Provider* under paragraph (n), the *Transmission Network Service Provider* must provide *NEMMCO* with the revised information as soon as practicable.

(p) Information made available to *Market Participants* as part of, or in connection with, the *congestion information resource* by *NEMMCO* and *Transmission Network Service Providers* under this rule 3.7A:

(1) represents a *Transmission Network Service Provider's* current intentions and best estimates regarding *planned network events* at the time the information is made available;

(2) does not bind a *Transmission Network Service Provider* to comply with an advised *outage* program; and

(3) may be subject to change due to unforeseen circumstances outside the control of the *Transmission Network Service Provider*.

[2] Clause 3.13.4 Spot market

After clause 3.13.4(x), insert:

(y) At intervals to be determined by *NEMMCO* under rule 3.7A(e), *NEMMCO* must, in accordance with the *timetable*, publish the updates to the *congestion information resource.*

New Chapter 10 Glossary Terms

congestion information resource

An information resource comprising :

(a) information on *planned network events* that are likely to materially affect *network constraints*;

(b) information on the incidence of congestion in the *National Electricity Market* through the use of historical data on *mis-pricing* at *transmission network* nodes in the *National Electricity Market*; and

(c) any other information that *NEMMCO*, in its reasonable opinion, considers relevant to implement the *congestion information resource objective*,

that is developed, *published* and amended from time to time, by *NEMMCO* in accordance with rule 3.7A.

congestion information resource guidelines

Guidelines developed and *published* by *NEMMCO* in accordance with rule 3.7A(k) to (m) relating to the *publication* of the *congestion information resource*.

congestion information resource objective

The objective of the *congestion information resource* which is set out in rule 3.7A(a).

mis-pricing

For a particular *network* node within a nominated *region*, the difference between:

(a) the *regional reference price* for the *region*; and

(b) an estimate of the marginal value of *supply* at the *network* node, which marginal value is to be determined as the price of meeting an incremental change in *load* at that *network* node.

network support agreements

An agreement between a *Network Service Provider* and a *Market Participant* to provide a non-network alternative to a network augmentation to improve network capability.

planned network event

An event which has been planned by a *Transmission Network Service Provider*, *NEMMCO*, or a *Market Participant* that will materially affect *network constraints* in relation to the *transmission system* including but not limited to:

(a) a *network outage*;

(b) the *connection* and *disconnection* of *generating units* or *load*; or

(c) the commissioning or decommissioning of a *network* asset and new or modified *network control ancillary services*; and

(d) *network support agreements*.

Chapter 11 Savings and Transitional Arrangements

11.X Savings and transitional arrangements as a result of the Congestion Information Resource

11.X.1 Definitions

In this rule 11.X:

interim congestion information resource means the information resource developed and *published* in accordance with rule 11.X.2.

network outage schedule means a schedule developed by *NEMMCO* based on information received from *Transmission Network Service Providers* in accordance with rule 3.7A that lists the planned *network outages* on the *transmission system* for a period of up to two years in advance and that identifies the likelihood of each planned *network outage* proceeding following an assessment of forecast demand for the period of the planned *network outage*.

11.X.2 Interim congestion information resource

(a) Pending the development and *publication* of the *congestion information resource* under rule 3.7A, *NEMMCO* must develop an interim congestion information resource to implement the *congestion information resource objective* in accordance with this rule 11.X. *NEMMCO* is not required to follow the *Rules consultation procedures* in developing the interim congestion information resource.

(b) The interim congestion information resource must include:

(1) the network outage schedule;

(2) the incidence of congestion in the *National Electricity Market* through the use of historical data on *mis-pricing* at *transmission network* nodes in the *National Electricity Market*; and

(3) the following information on *network outages* planned for the subsequent thirteen months that, in the reasonable opinion of the relevant *Transmission Network Service Provider*, will have or are likely to have a material effect on transfer capabilities:

(i) details of the forecast timing and the facts affecting the timing of planned *network outages* and the likelihood that the planned timing will vary; and

(ii) details of the reasons for the planned *network outage*, including the nature, and a description, of the works being carried out during the planned *network outage*, if any;

(4) the following information on planned *network outages* referred to in subparagraph (3):

(i) an assessment of the projected impact on *intra-regional power transfer capabilities*¸ the accuracy of which must be appropriate to implement the *congestion information resource objective*; and

(ii) an assessment of the projected impact on *inter-regional power transfer capabilities*, the accuracy of which must be appropriate to implement the *congestion information resource objective*;

(5) any other information with respect to planned *network outages* referred in subparagraphs (3) and (4) that implements the *congestion information resource objective*; and

(6) any other information that *NEMMCO*, in its reasonable opinion, considers relevant to implement the *congestion information resource objective*.

(c) Each month, in accordance with the *timetable* for the provision of information to *medium term PASA*, each *Transmission Network Service Provider* must provide to *NEMMCO*:

(1) the information referred to in (b)(3); and

(2) for the purposes of paragraph (b)(5), any other information with respect to the planned *network outages* referred to in paragraphs (b)(3) and (b)(4) that implements the *congestion information resource objective*.

(d) *NEMMCO* must *publish* the interim congestion information resource by [DATE A].

Note: DATE A is intended to be 6 months after this Rule commences operation.

(e) For the purposes of the *congestion information resource guidelines published* under rule 3.7A(k), the interim congestion information resource is taken to be the *congestion information resource.*

(f) *NEMMCO* must determine the frequency of updating (whether in whole or in part) and *publishing* the interim congestion information resource which must be included in the *timetable*.

(g) At intervals to be determined by *NEMMCO* under paragraph (f), *NEMMCO* must in accordance with the *timetable*, publish the interim congestion information resource.

(h) *Transmission Network Service Providers* must provide *NEMMCO* with such information as is requested by *NEMMCO* for inclusion in the interim congestion information resource. This information is to be provided to *NEMMCO* in a form which clearly identifies *confidential information*.

(i) Where there has been a material change in the information provided by a *Transmission Network Service Provider* under paragraph (h), the *Transmission Network Service Provider* must provide *NEMMCO* with the revised information as soon as practicable.

(j) Information contained in the interim congestion information resource:

    (1) represents a *Transmission Network Service Provider's* current intentions and best estimates regarding *planned network events* at the time the information is made available;

    (2) does not bind a *Transmission Network Service Provider* to comply with an advised *outage* program; and

    (3) may be subject to change due to unforeseen circumstances outside the control of the *Transmission Network Service Provider*.

H Glossary

AC	alternating current
ACCC	Australian Competition and Consumer Commission
ACF	alternative constraint formulation
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AGC	Automatic Generation Control
ANTS	Annual National Transmission Statement
APR	Annual Planning Report
CBR	constraint based residue
CCGT	combined cycle gas turbine
CIR	Constraint Information Resource
CM Regime	Congestion Management Regime
CMR	Congestion Management Review
CMV	Cumulative Marginal Value
COAG	Council of Australian Governments
Commission	see AEMC
CPI	Consumer Price Index
CRA	Charles River Associates
CRNP	cost reflective network pricing
CRR	Comprehensive Reliability Review
CSC	Constraint Support Contract
CSP	Constraint Support Pricing
DC	direct current
DPR	direct physical representation
DSM	demand side management

DSP	demand side participation
EHV	extra high voltage
ERA	Economic Regulation Authority of Western Australia
ERAA	Energy Retailers Association of Australia
ERIG	Energy Reform Implementation Group
ETC	Electricity Transmission Code of South Australia
ETNOF	Electricity Transmission Network Owners Forum (now known as "Grid Australia")
ETS	Emissions Trading Scheme
EUAA	Energy Users Association of Australia
FCAS	frequency control ancillary service
FTR	financial transmission right
GNP	generator nodal pricing
IES	Intelligent Energy Systems
IRSR	inter-regional settlement residue
kV	kilo volt
LHS	left hand side
LNG	liquid natural gas
LRMC	long run marginal cost
LRPP	Last Resort Planning Power
MAR	maximum allowable revenue
MCC	marginal cost of constraints
MCE	Ministerial Council on Energy
MEU	Major Energy Users
MMS	Market Management System
MNSP	Market Network Service Provider
MRET	Mandatory Renewable Energy Target

MSORC	Market and System Operator Review Committee
MT PASA	medium term PASA
MW	megawatt
MWh	megawatt hour
NCAS	Network Control and Ancillary Services
NECA	National Electricity Code Administrator
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NEMMCO	National Electricity Market Management Company
NEO	National Electricity Objective
NGF	National Generators Forum
NGMC	National Grid Management Council
NLCAS	network loading control ancillary service
NOS	Network Outage Schedule
NPV	net present value
NSA	network support agreement
NSCS	Network Support and Control Services
NSP	Network Service Provider
NSW	New South Wales
NTFP	National Transmission Flow Path
NTNDP	National Transmission Network Development Plan
NTP	National Transmission Planner
OCC	outage cost of constraints
OTC	over the counter
PASA	Projected Assessment of System Adequacy

PFC	Positive Flow Clamping
PIL	Pure interconnector limit
PNO	planned network outage
POE	probability of exceedance
QNI	Queensland – NSW interconnector
REC	Renewable Energy Certificate
Review	Congestion Management Review
RHS	right hand side
RIEMNS	Review of the integration of energy markets and network services
RIT-R	Regulatory Investment Test for Transmission
RPAS	reactive power ancillary service
RRN	Regional Reference Node
RRP	Regional Reference Price
Rules	National Electricity Rules
SA	South Australia
SCO	Standing Committee of Officials
SECV	State Electricity Commission of Victoria
SFE	Sydney Futures Exchange
SLF	static loss factor
SOO	Statement of Opportunities
SRA	settlement residue auction
SRC	Settlement Residue Committee
SRMC	short run marginal cost
ST PASA	short term PASA
SVC	static var compensator
TCC	total cost of constraints

TEC	Total Environment Centre
TNSP	Transmission Network Service Provider
TUOS	Transmission User of Service
TWh	terawatt hour (= 1 million MWh)
VoLL	value of lost load
VPX	Victorian Power Exchange

This is the last page of the Congestion Management Review Final Report