AUSTRALIAN ENERGY MARKET COMMISSION

Congestion Management Review

Issues Paper

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Abbreviations

AC	alternating current
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
ANTS	Annual National Transmission Statement
ASX	Australian Stock Exchange
BETTA	British Electricity Trading and Transmission Arrangements
BM	balancing mechanism
BSUOS	balancing services use of system
CAMMESA	Compañía Administradora del Mercado Mayorista Eléctrico (Wholesale Electric Market Management Company, Argentina)
Code	National Electricity Code
Commission	See AEMC
CRA	Charles River Associates
CSC	constraint support contract
CSP	constraint support pricing
EGR	Electricity Governance Rules (New Zealand)
FCAS	Frequency Control Ancillary Service
FTR	Financial Transmission Rights
GCAC	Generation Cost Assessment Committee
IESO	Independent Electricity System Operator (Ontario)
IRSR	inter-regional settlements residue
ISO	Independent System Operator
ISP	imbalance settlement process

KPX	Korean power exchange (Korean operator of the power system and electricity market)
LHS	left hand side
LMP	Locational Marginal Pricing
LRPP	Last Resort Planning Power
MARIA	Metering and Reconciliation Information Agreement (New Zealand)
MCE	Ministerial Council on Energy
MEM	Mercado Eléctrico Mayorista (Wholesale electricity market, Argentina)
MEMSP	Mercado Eléctrico Mayorista del Sur de Patagonia (Southern Patagonia wholesale electricity market)
MNSP	Market Network Service Provider
MWh	Megawatthour
NCAS	Network Control Ancillary Service
NEC	See Code
NECA	National Electricity Code Administrator
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM dispatch engine
NEMMCO	National Electricity Market Management Company
NEMMF	National Electricity Market Ministers' Forum
NSA	network support agreement
NTFP	national transmission flow path
NZEM	New Zealand Electricity Market
OTC	over the counter
Parer Report	"Towards a Truly National and Efficient Energy Market", Report from the Council of Australian Governments, 2002
PJM	Pennsylvania-New Jersey-Maryland market (USA)
PSS	price setting schedule
Review	MCE-directed Congestion Management Review

RHS	right hand side
RIEMNS	Review of the Integration of the Energy Market and Network Services
RRN	Regional Reference Node
RRN	Regional Reference Price
RSC	Resource Scheduling and Commitment (security-constrained unit commitment in PJM-USA)
Rules	National Electricity Rules
SFE	Sydney Futures Exchange
SIC	Central Interconnected System (Chile)
SING	Interconnected System of Norte Grande (Chile)
SPD	scheduling pricing and dispatch
SRA	settlements residue auction
SRMC	short run marginal cost
STNET	Study network (AC security network analysis model used in PJM-USA)
TNSP	Transmission Network Service Provider

Preface

The effective management of congestion is critical to an efficiently operating electricity market. Congestion occurs when the available transmission capacity means electricity demand cannot be met using the lowest cost generation available. It would not be cost effective to invest in the transmission network to remove all congestion. This means that some congestion is inevitable. The approach to managing this congestion can have serious implications for the efficiency of the National Electricity Market (NEM).

Congestion management is vitally important to the security of the electricity system. If electricity transmission lines breach their technical limits this may result in injury, equipment damage, load shedding and potentially the shutdown of part, or all, of the network. Such interruptions can impose considerable economic costs on the community.

Congestion management has other economic effects. If the congestion occurs between regions in the NEM, it will lead to price separation between regions, typically resulting in customers in the importing region paying higher prices. If congestion occurs within a region it can result in incentives for market participants to behave inefficiently and this may adversely affect price outcomes. These factors can adversely affect investment signals and make it difficult for market participants to manage their risk effectively.

The Ministerial Council on Energy (MCE) directed the Commission to undertake this Review to investigate the effectiveness of the current congestion management regime in the NEM and to consider improvements in congestion management. The Commission believes that any improvements will need to be considered in the context of the degree to which options for congestion management:

- provide certainty and practicality;
- facilitate the risk management of financial and physical trading in the NEM;
- promote the efficiency of the NEM, in terms of dispatch, pricing and investment; and
- promote reliability of supply and security of the power system.

The NEM objective, set out in the National Electricity Law (NEL), and the terms of reference will guide the Commission in undertaking this Review. Any proposed improvements to the approach to congestion management must contribute to more efficient investment in, and use of, electricity services and benefit consumers in the long-term. The implications of any changes to the congestion management regime for reliability and security will be considered in this context.

This Issues Paper seeks views from stakeholders on:

- specific network issues that the current approach to congestion management has failed to address adequately;
- problems and issues with the current approach to managing congestion in the NEM, and some indication as to the materiality of these problems; and
- options for improving the management of congestion in the NEM.

While it is important to ensure the detail of any proposal is thoroughly considered, the Commission believes that it is important to have regard to the issues of congestion management in the context of the real and practical congestion problems faced in the NEM. Without a strong link to practical congestion problems, identified solutions may not prove workable. With that in mind, the Commission is interested in understanding existing congestion management issues and examples in detail, as well as the reasons why these issues may not have been addressed by the current approach to congestion management.

These examples will assist in considering and assessing the broader congestion management issues faced in the NEM. Such systemic issues may include inefficient dispatch due to binding constraints and/or the approach used to manage negative settlements residues, inappropriate or limited investment incentives, difficulties for participants in the management of trading risks arising from congestion, failure of the regional structure of the NEM to evolve and potential concerns over the transparency of congestion management. The Commission is interested in stakeholder views regarding the nature of the problems with the current approach to congestion management in the NEM, and the materiality of these problems.

The Commission also invites stakeholders to express their views about options to improve congestion management. Possible solutions should be workable, effective, economically efficient in the long-term and take into account the level of development of the market. In order to elicit views from stakeholders this Paper raises a number of different approaches to managing congestion in the NEM. The Commission welcomes the views of stakeholders on the costs and benefits of these potential approaches and any alternative congestion management proposals that have not been canvassed in this Paper.

Interested stakeholders are invited to make comment on the issues outlined in this Paper. Submissions should be received by 5pm on 13 April 2006. Submissions can be sent electronically to submissions@aemc.gov.au or by mail to:

Australian Energy Market Commission
PO Box H166
AUSTRALIA SQUARE NSW 1215

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1 Introduction

1.1 The Review

On 5 October 2005 the Australian Energy Market Commission (AEMC or Commission) received a direction from the Ministerial Council on Energy (MCE) under s.41 of the National Electricity Law (NEL) to conduct a review of the requirements for and scope of enhanced trading arrangements relating to congestion management and pricing (the Review).[1] The direction is set out in the terms of reference for the Review (Appendix 1).

1.1.1 Terms of reference

The terms of reference for the Review require the Commission to investigate three key areas. Firstly, the Review is expected to identify and develop improved arrangements for managing financial and physical trading risks associated with material network congestion. The MCE specified that the objective of these arrangements should maximise the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM). Secondly, the MCE's direction requires the Commission to examine the feasibility of a constraint management regime as a mechanism for managing material congestion issues, until those issues can be addressed through investment or a region boundary change. Thirdly, the direction requires the Commission to take account of and clearly articulate the relationship between a constraint management regime, constraint formulation, region boundary review criteria and review triggers, the Annual National Transmission Statement (ANTS) flow paths, the Last Resort Planning Power (LRPP), the Regulatory Test and transmission network service provider (TNSP) incentive arrangements.

In conducting this Review, the terms of reference require the Commission to have regard to a report prepared by Charles River Associates (the CRA Report) in September 2004, entitled "NEM – Transmission Region Boundary Structure", including submissions to that report.[2] The MCE also directed that the results and broader impacts of the current limited trial of constraint support pricing/constraint support contract (CSP/CSC) in the Snowy region be taken into account by the Commission in conducting this Review.

The MCE has requested a report outlining the Commission's proposals for improved congestion management arrangements, including any draft Rules to support the Commission's proposals. Under the current timetable, the Commission intends to provide its Final Report to the MCE in September 2006.

1.1.2 Key themes

A key question which this Review seeks to address is whether the current approach to managing congestion in the NEM is efficient, or if there is another, more optimal set of arrangements. In the context of the NEM objective and the terms of reference for the Review, the Commission considers that an effective congestion management regime should:

1. *Improve certainty and practicality*. For efficient risk management, efficient operation and efficient investment, participants need to understand and be able to predict the likely effects that the congestion management regime will have on the NEM. A regime which is clear in its approach, transparent in its operation and provides certainty to those

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1 The NEL is contained in the Schedule to the National Electricity (South Australia) Act 1996 as amended by the National Electricity (South Australia) New National Electricity Law Amendment Act 2005.

2 CRA, *NEM – Transmission Region Boundary Structure, Final Report* submitted to the MCE, Melbourne, September 2004

affected by it, encourages participation and informed investment and contributes to a more efficient operation of the NEM.

2. *Facilitate risk management.* NEM participants face both financial and physical trading risks as a result of congestion. An effective system of risk management should allow participants to manage risk efficiently, including the opportunity to trade risk to parties that are in the best position to manage those risks. Effective risk management should provide greater certainty to market participants and investors, reduce barriers to entry to the market and increase the efficiency of the operation of the market.

3. *Ensure the efficiency of the NEM.* An effective congestion management regime should promote economic efficiency both in the short run, in terms of efficient dispatch and pricing, and in the long run, in terms of efficient investment.

4. *Protect the reliability of supply and security of the power system.* The first three themes must be considered in the context of protecting reliability of supply and security of the power system. Any congestion management regime cannot put at risk the security of the power system. The Commission will be conscious that any proposed changes to the congestion management regime should not result in any degradation of system security.

These themes provide a framework to consider the current regime and to assist in assessing any proposed improvements. Developing an effective congestion management regime that promotes these four components is likely to contribute to the NEM objective and provide benefits to all those using the market. In developing this regime it may be necessary to make trade-offs between the key themes. For example, economic efficiency may be promoted by sharper congestion pricing signals, but this may in turn have implications for the ability of participants to manage risk effectively.

1.2 Related Rule changes

The Commission is considering a number of National Electricity Rule (Rule) change proposals that relate to the management of congestion in the NEM. The Rule proposals identify a number of issues and present a range of solutions to these issues.

The Rule changes currently before the Commission which it considers relate to this Review include:

1. Loop flows and negative residues Rule change from the Southern Generators and National Electricity Market Management Company (NEMMCO);
2. Snowy regional boundary Rule change from Snowy Hydro Limited;
3. Snowy regional boundary Rule change from Macquarie Generation;
4. Reform of Regional Boundaries Rule change from the MCE;
5. Economic Regulation of electricity transmission revenue and pricing Rules Rule change, being undertaken by the AEMC (the Chapter 6 Rule proposal);
6. Last Resort Planning Power Rule change from the MCE; and
7. Reform of the Regulatory Test principles Rule change from the MCE.

The Commission is considering each of these Rule changes in line with the formal Rule change process, including inviting submissions from stakeholders.

The Commission recognises that the overlap of the subject matters of these Rule changes and the Review mean that they should not be considered in isolation. The problems that proposals 1 to 4 are trying to address are specific examples of some of the broader issues under consideration in this Review. The solutions proposed may provide possible tools in addressing similar problems more generally. For example, in the regional structure of the NEM region boundary changes are a key congestion management tool. It is important that the broader approach considered in the Review is consistent with the process, triggers and timing for a region boundary change, considered in proposal 4. The Commission will consider the merits of the proposed Rule changes in each case. The potential broader application of the proposed solutions will be considered as part of this Review.

Rule proposals 5 to 7 above seek to address problems identified in transmission planning, efficient transmission investment and the associated appropriate incentive arrangements. All these components are important in an efficient congestion management regime. The Commission will consider the proposed solutions to these problems in the context of the specific Rule change.

As improved processes and solutions are developed, the Commission will be able to consider them in the Review. Therefore, to the extent appropriate, the Commission intends to consider and progress these proposals in parallel.

This process will enable an integrated approach to considering congestion management in the NEM. It will also allow stakeholders maximum opportunity to respond to individual proposals within an informed policy environment. Stakeholders will also be able to identify what they consider to be the most important interactions between the Rule change proposals and the Review.

A more detailed description of these Rule change proposals is included in Appendix 2.

1.3 Structure of the Issues Paper

This Issues Paper is structured as follows. Section 2 sets the context for the Review by explaining what congestion is, why it can be an issue and giving a brief history of the evolution of congestion management arrangements in the NEM. Section 3 describes the proposed assessment criteria for evaluating arrangements for managing congestion. Section 4 identifies issues with the existing approach. Section 5 presents a range of options on how current arrangements could be improved.

Additional material is provided in a number of Appendices. Appendix 1 contains the MCE's terms of reference for this Review. Appendix 2 describes the Rule change proposals listed in Section 1.2. Appendix 3 presents an example of a congestion management tool in use in the NEM in Far North Queensland. Appendix 4 discusses different types of constraints and the implications for pricing arrangements. Appendix 5 discusses counter price flows in the NEM. Appendix 6 presents a survey of congestion management in electricity markets around the world.

2 Congestion management

Before considering issues associated with the management of transmission congestion in the NEM it is useful to outline the concept of congestion management. This Section broadly defines transmission congestion, before discussing why the management of congestion is important. In addition, this Section outlines the existing tools used to manage congestion in the NEM and briefly reviews the experience of congestion in the NEM.

2.1 What is congestion?

In broad terms network congestion occurs when the available network capacity cannot accommodate the dispatch of the least-cost combination of available generation to meet demand across the network. Congestion therefore affects the pattern of generator dispatch, since it usually creates a need to dispatch higher cost generators (or reduce load) in order to meet demand.

It would not be cost effective or efficient to eliminate all transmission congestion as this would lead to over investment in transmission capacity. The costs of doing so would be prohibitively high compared to the likely benefits.

Congestion management is therefore necessary to maintain the physical and operational security of the power system and has important implications for spot prices, the degree of competition, the bidding incentives for market participants and the level of price and volume risk borne by participants. In the long-term, the manner in which congestion is managed 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.

2.2 Sources of congestion

The capacity of the transmission network is limited by certain technical characteristics. In broad terms these are known as thermal and 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; and
- *Stability limits* refer to the need to keep the transmission system operating within design tolerances for voltage, ability to recover from disturbances, interaction of control systems and other technical characteristics that are important to keep the power system intact. Limits tend to vary with the location and quantity of generation and demand, as well as some other factors.

Violating technical limits on individual transmission lines may rapidly result in dangerous situations for the general public, equipment damage, or cascading load shedding that may ultimately lead to partial or full system shutdown. As a result, congestion in the electricity industry must be actively managed by the market and system operator to maintain power system security and reliability.

2.3 Managing congestion in the NEM

The National Electricity Rules (Rules) provide for the management of congestion by market institutions using a variety of tools and mechanisms. These arrangements may be separated into three categories:

- the Rules governing dispatch, including the way the power system is represented in the NEM dispatch engine, NEMDE;[3]
- the TNSP activities, including short-term arrangements for transmission availability and long-term incentives for transmission investment; and
- the Rules governing pricing and settlement, including the way prices are determined and settlement is carried out for each participant in the event of congestion within or between regions.

The complex nature of these Rules influences the level and movement in prices and together with a range of other factors results in trading risks for participants, who in this context play an important role in the management of congestion in the NEM.

An understanding of the way that congestion in represented and managed in the NEM is important for identifying areas in which the management of congestion could be improved. The way that congestion is currently managed in the NEM is discussed in more detail below.

2.3.1 Dispatch

The central dispatch process in the NEM has the objective of minimising the cost of supplying power to meet demand at each regional reference node, based on the bids and offers presented by market participants. In dispatching the system in the least-cost manner, NEMMCO must remain within predefined security and reliability parameters that are set out in the Rules.

Network constraints are represented in the dispatch process through constraint equations. NEMMCO formulates constraint equations for inclusion in the central dispatch process to ensure that the pattern of dispatch appropriately reflects the physical limitations of the network.

There are several thousand constraints that are taken into account by NEMMCO in the dispatch process. Many of these constraints are designed to accommodate certain contingencies in the power system; for example, the removal of a transmission line from service due to an outage. In general, a separate constraint equation may be required for each potential contingency that materially impacts the 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.

2.3.2 Transmission

The transmission arrangements, including TNSP connection and access agreements, TNSP incentive regimes and transmission investment and planning arrangements, are an important component of the congestion management regime. The NEM operates under an open access regime for networks.

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3 NEMDE schedules, prices and dispatches the spot market every five-minutes on the basis of bids and offers submitted by market participants. NEMDE contains an approximation of the underlying physical network, represented as a series of mathematical equations. Each five minutes, NEMDE aims to find the pattern of dispatch that minimises the cost of supplying energy to meet demand at each regional reference node, subject to the physical limitations of network and generation plant, and power system security constraints.

Participants in the NEM enter into agreements with TNSPs for access to the transmission network. These are known as connection and access agreements. These agreements provide non-firm physical (and financial) access to the market, since access to the transmission network is contingent on the availability of network capacity.[4] This contrasts to firm access arrangements, where participants are guaranteed access to a particular market price for their output through a set of financial compensation arrangements. The lack of financial firm access effectively means that access to the market (and the market price) for a generator is determined on an open access basis through the dispatch and settlement processes on a five minute by five minute basis.

The technical limits on the network are affected by the design and operation of the transmission network. Both are related to the regulatory regime imposed on transmission networks and the economic incentives this regime creates. The regulatory arrangements create incentives for TNSPs to maximise network availability by putting a material proportion of their regulated revenue at risk. As part of each TNSP's revenue cap decision, the Australian Energy Regulator (AER) links approximately +/-1 per cent of the TNSP's revenue to network 'service standards', which are also set by the AER. The purpose of the service standards regime is to provide incentives for TNSPs to make their networks available, especially at times they are likely to be of most benefit to the market. TNSP performance incentive regimes are being considered as part of the review of Chapter 6 of the Rules.

Transmission investment and planning arrangements are designed to promote efficient transmission investment having regard to the interaction between the competitive wholesale market and regulated transmission activities. There is a range of tools used to manage transmission investment in the NEM, including:

- the ANTS, which provides stakeholders with information about existing and potential future transmission limits, with particular focus on specific national transmission flow paths (NTFP);[5]
- the Regulatory Test, which assesses the relative benefits of transmission investment compared to the alternatives available. The Regulatory Test is designed to promote transmission investment either where it is the least-cost means of satisfying reliability criteria or where it is the option that maximises the net benefit to the market;
- network support agreements (NSAs) and network control ancillary service (NCAS) contracts which provide mechanisms for contracting with generation or load to assist in the management of network limits where this is more efficient than engaging in transmission investment. Appendix 3 discusses the experience of NSAs in Far north Queensland; and
- the proposed LRPP, which intends to provide a mechanism for ensuring potentially viable investment is not overlooked.

2.3.3 Pricing

The regional structure of the market is a key design feature of the NEM. Regional boundaries were initially established at the points across the NEM where the transmission network connection was weak (or non existent) and, hence, where congestion was greatest and/or more likely.

Congestion can result in price differences between regions. These regional price differences are intended to reveal the cost of this congestion so that market participants can determine when and

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4 Clauses 5.5 and 5.5A in the National Electricity Rules provide for compensation in the event a participant is constrained on, but in practice these clauses do not form part of standard TNSP connection and access agreements.

5 The glossary of the Rules defines an NTFP as 'that portion of a transmission network or transmission networks used to transport significant amounts of electricity between major generation or load centres'.

where it is efficient to invest to avoid the costs associated with congestion. Possible responses include participants altering their bids and offers, and in the longer-term investment in generation, network, demand side management or non-electricity alternatives.

The extent to which congestion within regions is reflected in wholesale prices depends on the type of constraint, as discussed in Section 4.2.1.

2.3.4 Risk management

Incentives provided by price separation highlight the important role that market participants play in managing congestion. The regional design of the NEM means that there is a strong relationship between the incidence of network congestion and the trading risks for participants. While regional price separation can provide a measure of the cost of network congestion and a price signal that an economic response may be required, it also creates a trading risk for participants buying from one region and selling into another, or producing electricity in one region and selling into another.

The two main forms of managing this risk are:

- financially, for example by participating in settlements residue auctions (SRAs) to purchase a share of inter-regional settlements residues (IRSRs), or by entering into a bilateral contract with a participant in another region; and
- physically, by reducing demand (for example by encouraging customers to use an alternative energy source) and/or increasing supply (through generation, network, demand side management and non-electricity alternative investment in the longer-term) in response to congestion.

Alternatively, participants could avoid this risk by choosing not to trade inter-regionally.

The effectiveness of these arrangements—dispatch, transmission, pricing and risk management—is a key theme for this Review.

2.4 Experience of congestion in the NEM

2.4.1 Experience of congestion

The cost of congestion can be defined as the additional cost of meeting demand with more expensive generation plant (or additional demand side response), when congestion occurs and the lowest-price available generation cannot be dispatched. It may be efficient for the NEM to bear this cost, given the cost of alternatives (such as investing in transmission to remove congestion). The Commission is particularly focused on inefficient congestion costs; that is, costs under the current approach to congestion management in excess of the costs which would arise under an optimal approach.

Unfortunately, there is no directly available data on the incidence or cost of congestion in the NEM and it would be difficult to calculate indirectly. Examining the duration of constraints in the NEM can provide a broad indication of the extent of transmission congestion. However, this approach has two main limitations:

- it provides no guidance on the materiality of congestion, for example the potential cost for participants associated with price separation between regions at times of congestion. In some cases a constraint may have little impact on costs and in other cases it may have a very significant impact; and
- it does not include situations where congestion arises but is already being addressed through means which avoid transmission constraints binding through the dispatch process. Possible mechanisms include the use of NSAs to avoid constraints, for example

in North Queensland (see Appendix 3), or operational measures by market participants to avoid a constraint binding and causing price separation.

Keeping these limitations in mind, Table 1 shows the hours of binding constraints each year in the NEM for the period 2000/01 to 2004/05. For each year the table shows:

- the hours of intra-regional constraints within each region; and
- the hours of inter-regional constraints by interconnector and direction.

Table 1: Hours of binding constraints in the NEM[6]

	2000/01		2001/02		2002/03		2003/04		2004/05	
	System Normal (Hours)	Outages (Hours)	System Normal (Hours)	Outages (Hours)	System Normal (Hours)	Outages (Hours)	System Normal (Hours)	Outages (Hours)	System Normal (Hours)	Outages (Hours)
Intra-regional Constraints by Region										
NSW	105	74	48	70	20	52	5	48	61	122
Qld	201	1,573	449	840	40	101	44	339	434	699
SA	0	0	0	7	0	43	0	76	0	272
Snowy	0	0	0	0	54	0	18	1	58	2
Tas	0	0	0	0	0	0	0	0	62	117
Vic	7	0	17	0	80	2	167	21	101	154
Inter-regional Constraints by Interconnector										
Directlink										
QLD->NSW	386	230	102	60	505	86	1,319	135	1,165	182
NSW->QLD	108	190	165	191	196	50	26	36	101	43
QNI										
QLD->NSW	10	281	100	335	52	397	413	121	327	201
NSW->QLD	75	3,160	116	134	165	18	7	7	16	15
SNOWY1										
NSW->Snowy	3	3	0	0	0	0	9	2	18	2
Snowy->NSW	0	1	2	4	4	2	3	3	41	5
Murraylink										
SA->Vic	0	0	0	0	117	28	486	87	222	140
Vic->VSA	0	0	0	0	560	1,033	709	346	536	555
V-SA										
SA->Vic	18	6	69	13	10	71	5	1	6	16
Vic->SA	1,317	243	316	238	598	1,180	898	1,661	1,435	1,484
V-SN										
Snowy->Vic	78	43	37	11	14	63	34	230	26	50
Vic->Snowy	713	43	438	57	635	635	1,036	160	712	276

The table separately reports the number of hours of constraint when relevant transmission lines were out of service (outages) as opposed to the hours when the system was operating under normal conditions (system normal).

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6 NEMMCO, *Statement of Opportunities 2005*, Table 13.11 Hours of Constraint, January 2005, p13-24

The historical data shows that:

- inter-regional constraints bind far more often than intra-regional constraints;
- while some constraints have declined in significance, in general the hours of binding constraints in the NEM is increasing over time, with the largest number of inter-regional constraints occurring in 2003/04 and intra-regional constraints in 2004/05; and
- the most frequently binding inter-regional constraint (Victoria to South Australia) occurred for around 16 per cent of hours in 2004/05. Intra-regional constraints bound for just over 8 per cent of the time in total in 2004/05.

The issues associated with the materiality of constraints are discussed in the context of the issues with the current congestion management regime in Section 4.

The extent and nature of congestion in the NEM is a function of a number of factors, including:

- the location and size of load, generation and network capacity;
- the Rules for operating the system and the market; and
- the interaction of those Rules with the bidding behaviour of participants.

Changing the way congestion is managed, like changing the regional structure of the NEM, may in turn change the incidence and pattern of congestion in the NEM. For example, a change in the current congestion regime may result in congestion emerging in parts of the NEM where it has not previously been observed.

2.4.2 Existing congestion

The discussion above highlighted that there is a wide variation in the incidence of binding constraints in the NEM. The Commission is interested in understanding stakeholders' views on the materiality of constraints, including those constraints which are most material in terms of their effect on the efficiency of the NEM. Identification and assessment of the seriousness of existing constraints can provide useful guidance for the Commission in assessing the strengths and weaknesses of the current approach to congestion management compared to alternative arrangements.

Understanding the background to the development of these constraints, their underlying causes and the consequences of inaction in effectively addressing these issues also provides context for the Commission's broader considerations of the most effective approach to congestion management.

Perhaps most importantly, the Commission is interested in understanding why the distortions caused by these constraints are enduring, and have not been addressed at this point in the development of the NEM. An understanding of the practical consequences of failing to address these material congestion points would assist the Commission in its deliberations.

The Commission is open to considering recommendations on appropriate ways to address serious existing and enduring constraints in the short-term. If these serious constraints are having immediate and significant effects on market efficiency, it may be more appropriate to deal with them immediately, or within a defined timeframe, rather than expecting those issues to be dealt with by a congestion management regime that is designed to deal with emerging constraints over the longer-term. This would need to involve an assessment of the costs and benefits of the various courses of action. It may also be possible that some of these congestion issues remain on a legacy basis from the establishment of the NEM.

One example of this approach may be the treatment of boundaries in the Snowy region. In this regard, the Commission has received two Rule proposals: one from Snowy Hydro and one from Macquarie Generation. Both these proposals are seeking to change the Snowy Region boundary through the Rule change process. The Commission is currently considering the merits of these proposals, with reference to its statutory obligations, the NEM objective and Rule making test. As indicated in Section 1.2 of this Paper, the Commission intends to co-ordinate its consideration of these proposals and this Review. Another example of this approach could be identifying and addressing major legacy constraints where a timely and certain resolution would provide advantages for the efficiency of the NEM and a new baseline for any future congestion management arrangements to operate.

1. Do existing constraints have a material effect on the efficiency of the NEM? What is the nature and materiality of these constraints? Why is it that these constraints have not been addressed to date? Are there specific points of congestion that should be addressed in advance of the establishment of a new congestion management regime?

2.5 Development of congestion management in the NEM

This Section provides a brief history on key developments since the start of the NEM.

2.5.1 Pricing

The NEM spot market is priced on a regional basis. The NEM was established with five regions, and expanded to six regions when Tasmania joined on 29 May 2005.

Clause 3.5 of the Rules sets out criteria applying to the definition of a region, and the location of a regional reference node. The original version of the National Electricity Code (NEC or the Code) envisaged that region boundaries would be reviewed annually, and changed as required to reflect and price new points of congestion. The Australian Competition and Consumer Commission (ACCC) required the National Electricity Code Administrator (NECA) to review the associated criteria within two years, as a condition of Code Authorisation under the Trade Practices Act.[7] NECA undertook this task as part of its Review of the Integration of the Energy Market and Network Services (RIEMNS).[8] NECA released the stage 1 final RIEMNS report in August 2001, and submitted the (as yet unpublished) stage 2 final report to the NEM Ministers Forum (NEMMF) in January 2002 to assist its review of transmission.

In early 2002 as required by the Code, NEMMCO commenced a consultation process on proposed region boundaries to apply from 1 July 2003. Subsequently, the NEMMF commenced a policy review of transmission. After consultation with NECA and the ACCC, NEMMCO suspended its review of region boundaries until the policy review was complete.

In 2003, the NEMMF appointed the consultancy firm Firecone to review the institutional and regulatory framework for transmission. Firecone's report recommended, amongst other things, boundary criteria defined in economic rather than technical terms.[9] The MCE Communiqué of December 2003 indicated that the MCE would commission a study of the criteria, the process, and initial options for boundary change.[10]

In 2004, the MCE appointed consultancy firm CRA to undertake this work. CRA considered the issues of region boundary change criteria and process, constraint formulation and congestion pricing. CRA recommended a move away from the original region boundary approach by reducing the frequency of region boundary change reviews and introducing a form of intra-

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7 ACCC, *Applications for Authorisation: National Electricity Code, Final Determination,* 10 December 1997

8 NECA, *The Scope for Integrating the Energy Market and Network Services, Draft Report*, October 2000

9 Firecone, *Regulatory and Institutional Framework for Transmission*, *Final Report*, November 2003

10 Ministerial Council on Energy, *Reform of Energy Markets: Report to the Council of Australian Governments*, 11 December 2003. Attachment to Ministerial Council on Energy, Communiqué, 11 December 2003

regional congestion pricing and contracting to be implemented as an interim step.[11] The study recommended boundary change criteria based on improved economic efficiency of dispatch exceeding $1 million, or the impact on annual revenues for indicative generation investments, subject to a minimum size for any new region. A five yearly cycle for the review of region boundaries was recommended. The CRA report recommended a staged approach to congestion management, moving from taking no action, to the introduction of CSPs/CSCs for constraints which are significant but not persistent, through to region boundary changes for material and enduring constraints.

The MCE subsequently consulted with participants on the recommendations included in the CRA draft report. Those recommendations form the basis for the MCE's proposed staged approach to congestion management, discussed in more detail in Section 5. The CSP/CSC arrangements recommended by CRA were conceptual in nature and specifically tailored for the NEM. It was recognised that further analysis and consultation with market participants would be required to develop the proposal into a set of arrangements capable of being implemented in practice.

In June 2005, the ACCC approved a derogation from the Code to allow a limited trial to be initiated, partially applying a CSP/CSC framework to a persistent constraint within the Snowy region.[12]

2.5.2 Dispatch arrangements

At market start NEMMCO was required to consider how constraints would be managed in the NEM. The arrangements, which were approved by NECA, indicated that constraint equations would initially be sourced from the existing jurisdictional arrangements and incorporated into NEMDE. This resulted in inconsistent approaches to the formulation of constraints, based on historical operating practices. It was foreshadowed there was a need to progressively review the range of constraint equations to standardise their form.

NEMMCO subsequently initiated work on developing a consistent approach to constraint formulation. In March 2003, a report by CRA established a common taxonomy for different forms of constraint formulation.[13] The MCE Transmission Statement of May 2005 set out a view that all constraints should be in a consistent form that allows NEMMCO to control all the variables.[14]

NEMMCO has now established a network and frequency control ancillary services (FCAS) constraint formulation policy document consistent with the MCE Transmission Statement, and has initiated a priority order to convert existing constraint equations to the fully co-optimised formulation.[15] Due to the number of constraint equations, implementation of the conversion for priority constraints was expected to take 12 - 18 months from its start in July 2005.

There has also been significant development in relation to the taxonomy of constraints over the period since commencement of the NEM. Before the NEM started there was an expectation that it would be possible to clearly categorise constraints as either intra-regional constraints

11 For the recommendations see: CRA, *Region Boundary Structure*, September 2004. For further detail see: CRA, *NEM Regional Boundary Issues: Theoretical Framework*, *Final Report*, submitted to the MCE, Melbourne, 14 September 2004; and CRA, *NEM Regional Boundary Issues: Modelling Report, Final Report*, submitted to the MCE, Melbourne, 16 September 2004

12 ACCC, *Applications for Authorisation, Amendments to the National Electricity Code, Dispatching the market: CSP/CSC trial at the Tumut nodes, Final Determination,* 15 June 2005

13 CRA, *Dealing with NEM Interconnector Congestion: A Conceptual Framework, Final report* submitted to NEMMCO, Melbourne, 24 March 2003

14 MCE Statement NEM Electricity Transmission, May 2005

15 NEMMCO, *Priority Order for Implementing Fully Co-optimised Constraint Equations*, 28 June 2005. NEMMCO, *Network and FCAS constraint formulation*, Version 8, 4 July 2005

(constraints within a region) or inter-regional constraints (constraints between regions). As discussed in Section 4.1 and Appendices 4 and 5, these different types of constraints have different implications on prices. As the understanding and experience of network constraints develops, it is becoming clear that, in many cases, network constraints are a function of both intra-regional and inter-regional power flows. This was a key principle established in CRA's March 2003 report on constraints.[16]

2.5.3 Transmission

Following the start of the NEM, the ACCC authorised Code changes to allow for unregulated transmission investment by market network service providers (MNSP) and to provide timing advantages over regulated investment. MNSPs are merchant transmission owners who recover the costs of the transmission asset entirely by arbitraging the price difference between two regions. In contrast, TNSPs have regulated revenue streams, which are their primary source of revenue. There have been three MNSP investments: Directlink, Murraylink and Basslink. Murraylink, between South Australia and Victoria, has converted to regulated status; Directlink, between Queensland and NSW, is currently in the process of converting to regulated status; and Basslink, connecting Tasmania to Victoria, remains unregulated. The MCE Communiqué of December 2003 indicated an intention to remove the perceived timing advantages for unregulated investment.

Congestion management is also affected by short- and long-term incentives for transmission capacity. In May 2005 the MCE:

- endorsed the ACCC work to amend the Regulatory Test for transmission investment, to include competition benefits; and
- noted work by the ACCC to develop availability standards and incentives, with this work to be taken forward by the Commission and the AER.

The development of an improved incentive regime for TNSPs is currently being addressed under the review of transmission revenue and pricing Rules (Chapter 6 of the Rules) currently being undertaken by the Commission. Key issues for that review are considering TNSP incentives for efficient network investment, reliability and availability with the aim of aligning TNSP incentives with the needs of the NEM.

2. Given the development of the NEM and the recommendations of reviews undertaken to date, what are the significant priority issues for this Review?

16 CRA, *Dealing with NEM Interconnector Congestion*, March 2003

3 Assessment criteria

This Section considers the criteria the Commission will apply when considering alternative approaches to congestion management. It begins by discussing the conceptual framework before considering the approach to quantitative analysis. The themes for this Review, discussed in Section 1.1.2, serve as the basis of the assessment criteria.

3.1 Conceptual framework

3.1.1 The NEM objective

The NEM objective, by which the Commission must be guided when performing any of its functions and exercising its powers, is set out in the NEL as follows:

> *"The national electricity market objective is to promote efficient investment in, and efficient use of, electricity services for the long-term interests of consumers of electricity with respect to price, quality, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system."*[17]

As the terms of reference for the Review require the Commission to provide draft Rule changes that would enable implementation of any proposed arrangements, in addition to a report on the review of congestion management, the Commission will also need to have regard to the Rule making test, which states that:

(1) *The AEMC may only make a Rule if it is satisfied that the Rule will or is likely to contribute to the achievement of the national electricity market objective.*

(2) *For the purposes of subsection (1), the AEMC may give weight to any aspect of the national electricity market objective as it considers appropriate in all the circumstances, having regard to any relevant MCE statement of policy principles.*[18]

In undertaking this Review of congestion management, the NEM objective and the Rule making test described above are the critical reference points for making assessments.

3.1.2 Applying the NEM objective

The NEM objective is founded on the concept of economic efficiency, with explicit emphasis on outcomes; in this instance, the long-term interests of consumers. Specifically, it emphasises that the interests of consumers encompass not only the price at which services are provided, but also the quality, reliability, safety and security of the electricity system.

Economic efficiency has three principal dimensions, referred to as productive, allocative and dynamic efficiency. Each dimension is related to the congestion management arrangements. There is also potential for trade-offs between these dimensions of efficiency.

Productive efficiency requires that dispatch costs are minimised, and that the quality, reliability, security and safety of electricity services are provided in line with approved standards at the least-cost. The approach to congestion management may affect the use made of existing generation and network capacity. For example, different regulatory incentives for TNSPs may affect the availability of transmission capacity; different approaches to constraint formulation may affect the level of redundancy required in the network; and different approaches to the treatment of negative settlements residues may affect whether or not particular generators can be dispatched.

17 Section 7, NEL

18 Section 88, NEL

As discussed in Section 4 and Appendix 4, the approach to congestion management may also affect generator incentives to submit cost reflective offers, which in turn may affect the efficiency with which the existing capacity is operated.

The Commission will therefore consider how alternative approaches to congestion management affect:

- the competitive pressure on generators and their incentives to offer cost reflective prices;
- the incentives for TNSPs to make capacity available, and the ability of the market operator to make use of network capacity; and
- the efficiency of dispatch.

Dynamic efficiency requires that costs are minimised over time. This is advanced by arrangements for congestion management which support efficient investment in transmission, generation and demand-side alternatives. This in turn requires clear signals about the location and extent of congestion, and a robust approach to determining the requirement for regulated transmission investment as opposed to market responses.

Transmission investments are principally affected by regulatory arrangements, and in particular the application of the Regulatory Test. Generation investments are strongly affected by possible location sites, availability of fuel and water and planning approvals. They are also affected by the prices they receive in the wholesale market and by costs related to transmission, including connection charges, losses and the risk of being constrained-off.

The current pricing arrangements can create large price differentials between regions, in response to congestion, but not within regions. Moreover, the open access arrangements for transmission in the NEM mean that one participant's investment decision may affect the ability of other participants to transmit power to customers.

The Commission will consider the likely impact of alternative approaches to congestion management on the efficiency of generation and transmission investment—including the type and the location of investment—and the efficient use of demand-side options.

Allocative efficiency requires that electricity is provided in response to the preferences and valuations of customers, where those preferences are based on cost reflective prices. The congestion management arrangements play an important role in determining how electricity is priced for market participants. However, most consumers face prices which are substantially averaged. This may reduce the impact of the approach to congestion management on the prices they face. The Commission will consider the extent to which efficiency of use is affected by the approach taken to congestion management.

The approach to congestion management can have implications for the way NEMMCO manages the quality of electricity delivered to customers.[19] It is important that the security of the system is not compromised by any changes to the congestion management regime. This means that if the effect of one congestion management tool is to reduce NEMMCO's ability to ensure system security, there will need to be other compensating adjustments to ensure that system security is maintained. The approach to congestion management should not compromise system security, and the relative merits of alternative approaches to congestion management will need to be assessed with full regard to the costs of any additional arrangements required to ensure system security.

An important element of efficiency is the *transaction costs* faced by market participants. A key component of those transaction costs is the risk borne by market participants, and their ability to

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19 Quality refers to power system security, reliability and safety; as well as the characteristics (eg voltage, frequency, MVARS) that make the power suitable for use in electric-powered devices.

assess and manage those risks. The approach to congestion management is likely to affect the risks participants face from price separation in the market (that is, from parties to contracts facing different market prices). It may also affect the nature of instruments for managing risk, and access of market participants to those instruments. The Commission will assess how the approach to congestion management affects the risks borne by market participants, and their ability to manage those risks.

3.2 Quantitative analysis

The debate on the optimal arrangements for congestion management in the NEM to date has been largely qualitative. The existing analytical work has, however, increased the level of understanding about the effects of congestion on dispatch pricing, bidding incentives, and the efficiency of the market. This analytical work can inform and guide any quantitative modelling.

While information about the incidence of binding constraints is made available to market participants through dispatch data and published annually in the ANTS, this does not measure the materiality of the congestion that occurs, or the response of market participants to that congestion. In the context of this Review, the Commission considers that quantitative analysis will be beneficial in considering the materiality of any problems under the current congestion management arrangements and assessing the merit of alternative approaches to congestion management.

Any quantitative analysis needs to recognise the interaction between the congestion management regime, the bidding incentives for participants, the resulting patterns of dispatch and pricing and the associated trading risks for participants. This means it is important that quantitative modelling takes into account the way alternative congestion management options are likely to affect the behaviour of market participants, and therefore market outcomes including the efficiency of dispatch. The modelling approach must therefore be capable of accurately modelling the technical characteristics of the network, the means by which network flows are controlled, and the behavioural responses of market participants.

There are a number of questions that the Commission intends to consider when assessing alternative congestion management options:

- What is the effect of the option on dispatch and pricing, assuming a competitive market?
- What is the effect of the option on participant bidding incentives? What are the resulting implications for the extent of competition among participants, and the resulting dispatch and pricing outcomes?
- How does the option affect the financial trading risks faced by participants?

Any quantitative analysis will be used as an input to the Commission's broader thinking and analysis in the Review. Modelling analysis necessarily requires a number of assumptions to be made, and this may affect the applicability of the results. Moreover, there are a number of important questions that it is not possible to answer definitively through quantitative analysis, such as the effect of alternative congestion management regimes on investment in the longer-term.

3. What are the key questions the Commission should seek to examine quantitatively as part of the Review? What key factors should the Commission take into account in this modelling analysis?

4 The effectiveness of the current approach

The effectiveness of the current approach to congestion management in the NEM is a key consideration for this Review. This Section seeks to identify issues in the current framework for congestion management that could be improved. The Commission considers that these issues fall into three categories:

- elements of the Rules or current practice that reduce the ability of the market to operate efficiently, in terms of their effect on dispatch efficiency and in sending appropriate signals for efficient investment;
- elements of the Rules or current practice that do not enable participants to manage risk efficiently; and
- elements of the Rules or current practice that are not sufficiently transparent or clear or do not provide participants and investors with sufficient certainty to operate and invest effectively.

Underlying all of these is the need to maintain security. The Commission is of the view that it is important to consider these issues in that context.

This Section seeks stakeholder views on the issues that are acting as impediments to effective congestion management in the NEM under the current approach. This is necessary to ensure that the Commission can tailor proposed solutions to those issues that stakeholders consider to be the most material and enduring.

The Commission has been guided by the key themes for the Review in identifying the central issues associated with the current approach to congestion management. The issues identified in this Section should not be seen as an exhaustive list of all congestion management issues. The Commission encourages stakeholders to provide views on the issues that they consider to be material and significant within the current congestion management regime.

4.1 Constraint formulation and system security

As system operator, NEMMCO is responsible for maintaining power system security in accordance with Chapter 4 of the Rules. The inclusion of constraint equations in NEMDE is one of the key tools NEMMCO uses to deliver system security by ensuring the network operates within its limits.

Simply, a constraint is an equation included in the central dispatch process to ensure that the pattern of dispatch reflects the physical and security limitations of the network. If dispatch of the least-cost bids and offers would result in a network limit being exceeded, the constraints included in the central dispatch process ensure that network limits are not violated. The dispatch process is designed to deliver the lowest cost pattern of generation (based on offers from participants) to meet demand (based on bids from participants with dispatchable loads plus non-dispatchable demand) without violating any of the constraint equations. A constraint 'binds' when flow across it equals or exceeds the constraint limit.

The way in which a constraint is formulated has implications for system security and reliability, dispatch patterns and pricing outcomes. As noted in Section 2.4.2, it has been agreed that constraints should be formulated using a 'direct physical representation' or so-called 'option 4' [20]approach, which NEMMCO is in the process of introducing. Under this approach, all elements that affect flow on a transmission line—for example generating units, interconnector(s), and scheduled loads—are included as terms on the left hand side (LHS) of the network constraint

[20] NEMMCO, *Formulation of intra-regional constraints, Issues and Options Paper*, January 2002.

equation.[21] In simple terms variables on the left hand side of a constraint equation can be optimised or controlled within the dispatch process, while variables on the right hand side (RHS) of a constraint equation are assumed to remain unchanged from their most recently measured value. Under an 'option 4' constraint formulation, generally the network limit and other constants are on the RHS.

This approach to constraint formulation provides NEMMCO with greatest control over the power system. 'Option 4' has the desirable characteristics of enabling NEMMCO, as system operator, to control all the relevant variables in the constraint equation as part of the central dispatch process (ie. a fully co-optimised direct physical representation). This accords with the MCE's view expressed in its Statement on Transmission.

However, some problems can arise under an 'option 4' constraint formulation where intra-regional or hybrid constraints bind:

- first, as discussed in Section 4.2.2.1, remote intra-regional generators may have incentives to bid at prices below their true opportunity cost of supply which may result in inefficient dispatch and counter price flows; and
- second, even if intra-regional constraints do not lead to distorted bidding, it may lead to power flowing from a high-priced region to a low-priced one. This is known as a counter-price flow. This can reduce the value of IRSRs used to support inter-regional trading.

If an alternative constraint formulation was to be used, there is a risk that a network limit would be exceeded as some terms (eg. interconnector flow, generation output) may be assumed to be constant by the dispatch engine, when in reality, this may not be the case. This risk must be managed in some way, such as by the addition of a safety margin on transmission line limits to be used for purposes of dispatch. Such a safety factor would tend to reduce the capacity of the transmission element below that which would be available if an 'option 4' constraint form were used in the short-term, which may in turn accelerate the requirement for transmission investment in the longer-term. There are costs and benefits associated with any approach to constraint formulation.

4. Are there any material problems with the 'option 4' approach to constraint formulation to managing system security and reliability? How might such problems be addressed while continuing to maintain system security and reliability?
5. Are there any other problems, other than constraint formulation, with the management of system security in the context of the current congestion management regime? How might any such problems be addressed?

4.2 Efficiency

4.2.1 The impact of congestion on prices in the NEM

The pricing of congestion may be considered as an issue with the current regime because different types of constraints are reflected to differing extents in regional reference node prices. Ignoring the signal provided by the non-firm access regime, where a constraint is not priced, no

21 NEMMCO, *Network and FCAS constraint formulation*, 2005, p2. Note that NEMMCO's procedures allow for terms with very small coefficients to be included on the right hand side of a constraint equation to minimise the risk of significant fluctuations in dispatch and pricing outcomes when the dominant variable becomes constrained by a different constraint equation.

signal is given to the market as to the cost of that constraint. This means no incentive is provided to alleviate the constraint. If a constraint is only partially priced, those signals are muted. In the short-term, failure to fully price a constraint can give parties incentives which are not aligned with the interests of the broader market in alleviating constraints. In the longer-term, a failure to price a constraint may lead to a failure to appropriately manage that constraint, either through investment, a network support contract, or other means of congestion management.

However, it may not be efficient to price all constraints in the market. The pricing of a constraint creates price divergence between regions, and therefore reallocates risk to participants trading in the NEM. Additional pricing of congestion would also add significant levels of complexity for participants engaged in trading and this could create additional transaction costs and competitive barriers which may result in higher prices in the long-term. Given these potential disadvantages, a balance is needed between allowing prices to reflect the costs of congestion on one hand and not significantly adding to the risks and complexity faced by participants on the other.

The pricing rules in the NEM allow some, but not all, of the costs of congestion to be incorporated into regional prices. The extent to which the costs of congestion are reflected in regional reference prices depends on the nature of the constraint.[22]

One of the key tools for managing congestion in the NEM is price separation between regions when there is inter-regional congestion. An *inter-regional constraint* occurs where there is a limit on the power that can be transferred between two regions of the NEM that is independent of power flows within a region.

When there are binding constraints between regions the prices at adjacent regional reference nodes diverge, so that separate prices are determined for different regions.[23]

When there is an inter-regional constraint it is usually necessary for additional generation in the importing region to be dispatched, even though it may be more expensive than generators 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. The inter-regional price differences that emerge when constraints occur provide a guide to the short-term value of transmission capacity and send locational signals to potential investors.[24]

As the market evolves, through changing levels of demand or new investment, the flows of power across the network can change, meaning that the material points of congestion may change as well. The original Code envisaged that region boundaries would be reviewed annually and changed according to certain technical criteria to reflect and price new points of congestion.[25] However, review of region boundaries has been suspended by the MCE pending clarification of the arrangements for boundary change. The Commission is currently considering a Rule proposal, submitted by the MCE on this issue.

Congestion within regions is not priced in the same way as inter-regional constraints. An *intra-regional constraint* occurs when power flows within a region are limited (independent of flows between regions). Unlike inter-regional constraints, intra-regional constraints do not result in price separation between regions. The extent to which intra-regional constraints influence the regional reference price in their region depends on the location of generation, load and the

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22 Congestion can arise from four types of constraints: inter-regional, intra-regional, hybrid and trans-regional. These constraint types are referred to in the following text and explained in more detail in Appendix 4.

23 Prices may vary in the absence of constraints due to losses.

24 It is possible in the NEM for electricity to flow from high priced regions to low priced regions in some instances, known as counter price flows. This is discussed in more detail in Section 4.2.2.2.

25 Clause 3.5 of the National Electricity Rules

regional reference node relative to the constraints. If there is a binding intra-regional constraint between a generator and the regional reference node, the offers of that generator will have limited influence on the regional reference price.

The distinction between inter- and intra-regional constraints is not always clear. In practice congestion can be a function of both power flows between regions and power flows within regions. These could be considered to be *hybrid constraints*.

When a hybrid constraint binds there is price separation between regions, as is the case for inter-regional constraints. However, because hybrid constraints involve both inter and intra-regional power flows there is no clear means of distinguishing which power flow influenced the pricing outcome. This can make it difficult for market participants to understand the factors that influence pricing. In turn, this makes it difficult to predict prices and manage the risk of price volatility. The effect of hybrid constraints on regional reference node prices across the NEM depends on the relative location of the point of congestion, the regional reference node, the connection point(s) of the interconnector(s) and generation within the region. Hybrid constraints account for a large proportion of constraints in the NEM.

When the constraint is a function of the flows across two interconnectors joining differing regions this is known as a *trans-regional constraint*. Trans-regional constraints can have a number of pricing consequences including:

- "regional reference prices and inter-regional price differences may be set by various combinations of marginal offers in any of the regions involved;
- inter-regional price differences may arise across interconnectors which have not reached their specific capacity limits;
- counter price flows may be optimal in situations where flow on one interconnector supports flow on another; and
- much of the market 'settlement surplus' may be accounted for by rents on the trans-regional constraint and not obviously attributable to any particular interconnector or owner."[26]

These different types of constraints will affect both the pricing outcomes and the pattern of dispatch in different ways. This would suggest that care needs to be taken in ensuring that the approach to congestion management is robust enough to address the complexities of the actual constraints identified in the NEM. Appendix 4 provides a more detailed discussion of each constraint type and the pricing consequences of that constraint. The following Sections discuss some of the implications of the relationship between constraints and pricing for efficiency in the pattern of dispatch and investment.

4.2.2 Efficiency in dispatch

The central dispatch process in the NEM is intended to minimise the cost of supplying power to meet demand at each regional reference node, based on the bids and offers presented by market participants, while maintaining power system security.[27] The dispatch process is an important means of managing congestion. A dispatch process based on decentralised bids and offers can drive the market towards economically efficient pricing and use of electricity services in the short-run.[28] Where the dispatch process fails to minimise the economic cost of dispatch, consumers may face higher prices for electricity than necessary.

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26 CRA 2003, *NEM Interconnector Congestion: Dealing with Interconnector Interactions*, p.1

27 Clause 3.8.1(b) of the National Electricity Rules

28 Ring, B.J, *Dispatch Based Pricing in Dececntralised Power Systems*, PhD Thesis, University of Canterbury, Christchurch, 1995

4.2.2.1 *Bidding incentives for participants*

Congestion can cause inefficient dispatch by affecting a participant's incentives to bid in relation to their true costs as part of the dispatch process. The current design and operation of the NEM is predicated on the assumption that market participants have incentives to reveal costs in their bids and offers, and that dispatching the system based on those bids and offers is therefore efficient, or will tend toward efficient levels.

However, these incentives may be weakened if there is a binding intra-regional or hybrid constraint. In simplified form, if there is a binding intra-regional constraint between a generator and the regional reference node, the generator cannot influence the price set at the regional reference node. This will mean that the price the generator receives is unlikely to be influenced by its bidding behaviour.

This can result in a situation where participants offer at low prices, even submitting negative offers, as they compete to be dispatched, in the knowledge that their offers are unlikely to affect the price they receive (see also Appendix 4). These perverse commercial incentives can result in inefficiencies in dispatch and pricing, which can then result in more long-term inefficiencies.

Importantly, while the distorted bidding incentives created by a binding constraint may lead to inefficient dispatch, this is not necessarily the case. It may be that the generator whose bids are distorted by the constraint is actually the lowest-cost generator available to meet load. Therefore, whether the constraint leads to inefficiency would vary on a case-by-case basis.

6. How material are reductions in the dispatch and pricing efficiencies due to binding intra-regional constraints under the current arrangements? How can they be quantified?

4.2.2.2 *Managing counter price flows and negative settlements residues*

Counter price flows occur when the optimal pattern of dispatch (based on bids and offers) results in electricity flows from a high priced region to a low priced region, leading to an accrual of negative settlements residues. In some situations, counter price flows can be consistent with efficient dispatch as a result of transmission congestion. In other situations, counter price flows may occur as a result of distorted bidding (see above). Appendix 5 discusses in more detail the circumstances when counter price flows are likely to arise.

There may be concerns with the accumulation of negative settlements residues for a number of reasons. Under the current arrangements when negative settlements residues occur, NEMMCO offsets these residues against any positive residues within the trading week. This in turn reduces the positive residues accruing to IRSR unit holders. This reduces the usefulness IRSRs as an inter-regional hedging instrument.

Additionally, accumulation of negative settlements residues may have an impact on NEMMCO's financial and risk positions. At present, NEMMCO has concerns that the means of funding large negative residues is inadequate. Any negative residues in excess of positive residues for a particular trading week are carried forward by NEMMCO as a liability and recovered from future IRSR auction participants. The issues associated with the management and recovery of this liability are the subject of a separate Rule change proposal currently before the Commission.[29]

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[29] Australian Energy Market Commission, *Draft Rule Determination: Recovery of Negative Inter-Regional Settlements Residue*, 19 January 2006

The Rules provide for NEMMCO to manage counter price flows by applying an alternative constraint formulation for the duration of the counter price flows.[30] NEMMCO's procedures require it to intervene each time negative residues over the period of counter price flows are forecast to reach, or actually reach, an accumulated value of $6,000.[31] In most cases, NEMMCO currently manages counter price flows by directly limiting flow on the relevant interconnector, which could be referred to as 'clamping', to avoid the accumulation of negative settlements residues. However, there are special procedures for the management of negative settlements residues between Snowy to VIC and Snowy to NSW given the Snowy CSP/CSC trial (discussed in Appendix 4). The intervention is removed when NEMMCO is satisfied that this will not result in counter price flows.

While these arrangements allow NEMMCO to limit the accumulation of negative settlements residues, where dispatch was originally efficient, this intervention to manage counter price flows can result in inefficient dispatch and pricing outcomes.

7. How material are the reductions in dispatch and pricing efficiencies due to the management of negative settlements residues under the current arrangements? How can they be quantified?

4.2.3 Efficient signals for investment

Investment is another key response by participants to congestion. Participants can respond to the price signals and trading risks associated with congestion by:

- increasing supply (by investing in new generation); and/or
- reducing demand (through investing in demand side management or alternative energy sources).

The congestion management regime, including price signals, loss factors and transmission arrangements provide important locational signals to ensure investment is efficient.

The regional pricing structure of the NEM means that the locational signals arising from wholesale prices are reasonably muted across areas. This means that wholesale prices in the NEM provide dampened information about the requirement for investment at particular locations within a region because they contain limited information on the location costs of congestion within regions.

There are many locational signals for potential investors in the NEM. Loss factors, transmission connection charges and the physical risk of being constrained-off all create locational signals for potential investors. It may be the case that the location of new generators is primarily driven by the location of fuel and available sites. However, despite these locational signals, it is possible that a different set of congestion management arrangements in the NEM might result in a different, perhaps more efficient, pattern of investment.

30 Chapter 8 Part 8A of the National Electricity Rules

31 NEMMCO, *Operating Procedure: Dispatch,* SO_OP3705, 27 September 2005, p28

8. Have the existing arrangements resulted in materially inefficient investments? Could the existing arrangements result in materially inefficient investments in the future? What kind of inefficiencies may result?
9. How well do existing arrangements provide signals for efficient investment over time and locationally using the least-cost technology—generation, network demand side management or non-electricity alternatives?

4.3 Risk

Congestion, and the way that congestion is managed in the NEM, may involve the reallocation of risk to specific market participants. This Section considers the impact of two types of risk: financial and physical risk. The congestion management regime is an important determinant of the level and nature of risk borne by certain market participants, and their ability to manage that risk. For example, increasing the number of regions may increase the extent of inter-regional price separation, which in turn is likely to have implications for the cost of hedging for participants. On the other hand, it could reduce uncertainty about physical dispatch because the incidence of NEMMCO constraining-on or off generators in respect of their regional reference price may be reduced.

4.3.1 Risks arising from congestion

Electricity prices in the NEM vary throughout the day with movements in demand and supply. NEM spot prices can vary between -$1,000 and $10,000 per MWh over a trading day (the so-called VoLL limits). This price volatility results in risk for generators and retailers:[32]

- generators are exposed to the risk of low spot prices. They need to manage cash flows to meet financial obligations relating to operational and maintenance costs, fuel costs and financial charges; and
- retailers are exposed to the risk of high spot prices. They need to manage their gross margin, that is the difference between the price at which they purchase energy and the price that they charge customers for the energy they consume.

These risks are largely inverse, creating a potential for the parties to manage the risk by entering into financial contracts.

Participants in the NEM also face the financial risk of regional price separation. This means that writing contracts with participants in other NEM regions can result in some price exposure for market participants if their local regional reference price differs from the regional reference price at which the contract is struck. The extent of this inter-regional price risk depends on the frequency of constraints between regions and the divergence between regional prices at these times. Importantly, this price separation between regions can break the inverse relationship between generator and retailer risks, exposing one or other of the parties to inter-regional price risk.

Congestion also introduces the physical risk for market participants that they may be constrained-off or constrained-on. This means that there are times when participants could be dispatched for a price that is less than their offer price, or not dispatched even though their offer price is less than the regional reference node price.

32 ASX website, http://www.asx.com.au/investor/futures/electricity/index.htm, accessed 7 February 2006

A generator might be considered to be constrained-off when its offer price is less than the regional reference price, but it is not dispatched. This situation arises if a binding constraint means that it is not possible to dispatch the least-cost bids and offers to meet demand.

A generator could be considered constrained-on when its offer price is more than the regional reference price, and it is dispatched to meet demand. This situation arises because when a constraint binds, the price at the regional reference node is a combination of the offer prices of those generators whose output is increased to ensure that the network remains within operating limits. In such cases, multiple generators may be marginal, so that the regional reference price is not set solely by the highest offer price of an individual unit constrained on to manage the congestion.

Being constrained-on or constrained-off raises potential financial and physical risks for generators. This is because if they are constrained-on, it is possible that generators are being required to generate, but receive a price that is less than their operating costs. If they are constrained-off, they could be unable to earn the revenue required to cover their costs of meeting contract payments.

10. Does the potential to be constrained-off or constrained-on relative to the regional reference price result in material risks for market participants? How are those risks managed?

4.3.2 Risk management

Market participants undertake a range of actions to manage risk caused by congestion including participating in IRSR auctions to reduce and manage inter-regional price risk. Participants can also enter into financial contracts, capacity swap agreements or demand side management arrangements with participants in other regions to manage the risk of inter-regional trade.

In practice the extent to which participants attempt to mitigate inter-regional price risk depends on their assessment of the likely risk of inter-regional price differentials, including their size and duration, and the risk preferences of the participant. Alternatively, some participants avoid inter-regional price risk by choosing not to engage in inter-regional trade. If many participants decide to avoid inter-regional price risk by deciding not to engage in inter-regional trade this is likely to limit the depth of contract markets in the NEM.

4.3.2.1 Financial risk management

Participants in the NEM hedge their exposure to volatile spot prices primarily using financial or derivative contracts. These contracts are used to set or limit the price ultimately paid or received for wholesale electricity in the NEM. Financial contracts allow participants in the NEM to manage their exposure to the risk of adverse spot price movements (high or low, depending upon the participant's perspective).

There are a number of 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 other market participants (that is retailers or generators as set out earlier), 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) or the Australian Stock Exchange (ASX). 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 occurs using OTC contracts rather than through exchange traded contracts. There is limited publicly available information on OTC contract trading, however data on OTC trading is reported each year by the Australian Financial Markets Association (AFMA). This data has important limitations, since it is based on surveys of a limited number of market participants, but it represents the most comprehensive source of publicly available data on the OTC market. For electricity derivatives, AFMA reports OTC contract turnover, in MWh, by instrument, by region and by counterparty type. Table 2 summarises OTC electricity trading volumes. The volumes inTable 2 include trading in swaps, caps, swaptions, collars and Asian options, and other options.

Table 2: Annual turnover in OTC electricity derivatives[33]

	Annual OTC contract turnover in electricity derivatives (MWh)				Total (MWh)	Sent out demand (MWh)	Total OTC contract turnover as % of sent out demand
	Generators	Retailers	Intermediaries	Other			
2000-2001	91,460,820	88,541,605	23,258,126	0	**203,260,551**	160,261,000	127%
2001-2002	89,080,406	45,759,742	12,990,639	20,266,143	**168,096,930**	158,079,000	106%
2002-2003	133,562,781	77,424,803	23,937,959	107,295	**235,032,838**	162,709,000	144%
2003-2004	106,685,246	82,169,364	28,367,664	1,814,495	**219,036,768**	172,379,000	127%
2004-2005	99,350,598	60,570,699	36,935,853	2,018,866	**198,876,016**	176,144,000	113%

While sent out demand has grown relatively steadily since 2000-01, total trading volumes in electricity derivatives have been more volatile. Nevertheless, in each year since 2000-01, trading volumes in derivatives have been greater, although not significantly greater, than sent out demand.

Electricity derivatives can also be traded on organised exchanges. On the SFE, electricity derivatives are a result of a partnership between the SFE and d-cyphaTrade, a privately owned company. This partnership resulted in the launch of d-cyphaTrade SFE Australian Electricity Futures contracts in September 2002. There are eight contracts, based on peak period and base load electricity in NSW, Victoria, South Australia and Queensland. The contract unit for the baseload futures contract is 1 MW over the quarter. Trading volumes in these contracts are volatile, but increasing over time. Over the past year, trading volumes have tended to be around 2,000 contracts per month. Options on electricity contracts are also available for trade on the SFE through a partnership with d-cyphaTrade, although such options are predominantly traded OTC.

Electricity futures are also traded on the ASX. In October 2002, the ASX launched electricity futures contracts based on peak and off-peak electricity. These contracts never achieved any significant trading volumes, and there has been no trade in these contracts since January 2004.

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33 AFMA, Australian Financial Markets Report: Comprehensive, and NEMMCO Annual Report, 2005

The publicly available information on the contract market highlights several key points:

- there is limited publicly available data, which makes identifying and assessing issues associated with financial risk management difficult;
- while OTC contracts dominate, the available data indicates no clear direction in traded volumes; and
- attempts to develop exchange based trade have met with limited success to date.

The Council of Australian Governments' 2002 Report "Towards a Truly National and Efficient Energy Market" (Parer Report) raised concerns about the lack of liquidity and an effective inter-regional hedging mechanism, which in turn may result in a lack of interstate trading.[34] The term market liquidity refers to the ease at which participants are able to enter into financial contract arrangements of their choice. Liquidity is therefore often used as an indicator of the success or maturity of a financial market. Mature financial markets, such as bond markets, are generally very liquid—the total volume in derivative contracts traded is usually many times the value of the underlying bond.

Given most contract trades occur OTC and are therefore confidential, assessing liquidity in the context of the NEM is difficult. Another issue may be that in many cases liquidity concerns are raised in relation to non-standard products.

11. Do market participants face problems in managing risk due to the nature of the instruments available, or the liquidity of market for those instruments? If so, how are those problems related to the current approach to congestion management?
12. Are there problems in accessing information to support effective risk management in the context of congestion in the NEM? Is the lack of exchange based trading a problem in this context?

4.3.2.2 Inter regional settlements residues

When regional prices diverge, market participants are exposed to price and volume risks when trading across regions. The Rules provide a mechanism for managing inter-regional price risk when trading across regions through the auction of IRSR units. This Section considers the effectiveness of IRSR units as a risk management tool. It has a particular focus on whether the lack of 'firmness' of IRSR units limits their effectiveness as a tool to manage risk.

The IRSR is the revenue that accumulates at settlement as a result of customers paying more for imported electricity than the generators exporting electricity are paid.[35] Due to the fact that the IRSRs generally reflect the price differential between the two regions where they accumulate, they provide a useful hedging instrument to parties that trade between those regions.

NEMMCO periodically auctions the rights to shares of IRSR attributable to each direction of each notional interconnector in future periods. Units are auctioned quarterly up to a year in advance. The proceeds of the auction are paid to the owners of the transmission assets that

[34] Council of Australian Governments, *Towards a Truly National and Efficient Energy Market*, 2002, (Parer Report), p.164

[35] The IRSR is the economic rent that notionally accrues at settlement to the transmission asset owner as a result of power flows across the network. This transmission rental is also referred to as the transmission 'merchandising surplus'. The value of the transmission rental is influenced by marginal losses and congestion on the network and is equal to the difference in locational marginal prices between two points multiplied by the flow between those points. In the NEM, there are a limited number of locational marginal prices (ie. regional reference prices) and so only a limited number of IRSRs.

comprise the interconnector to offset network use of system charges and connection charges. Any settlements residues that accrue are paid to IRSR unit holders based on their share of IRSR units.

Typically, the IRSR has a positive value, indicating that the price paid in an importing region exceeds that paid in the exporting region. However, the IRSR can sometimes be negative, indicating the reverse—that is, power flows are counter to the price difference, from a high price region to a low price region.

The IRSR units do not provide a firm financial hedge against inter-regional price risk. This is because the IRSRs that accrue are a function of the direction and flow on the link over time and the units sold at the IRSR auctions are an entitlement to a proportion of the residues that accrue. If the flow on an interconnector is limited to less than the nominal rating used as the basis of the SRA, the amount of IRSR to be shared among IRSR unit holders will be reduced on a pro-rata basis, even though their financial exposure from price separation may be unchanged.

Some participants have expressed concerns that the non-firm nature of IRSRs reduces their effectiveness as an inter-regional hedging tool.[36] Similar concerns may arise in relation to the limited duration of the units that are auctioned (quarterly), and the limited degree to which they can be purchased on a forward basis, compared to the longer-term nature of many bilateral financial contracts.

13. Does the current design of IRSR units impact the ability of participants to efficiently manage inter-regional price risk?

4.4 Certainty and transparency

Section 4.1 noted that the original market design provided for the evolution of the regional structure of the NEM. However, this has not happened in practice. The MCE has intervened by placing a moratorium on region boundary change, and there has been considerable debate about the appropriate arrangements for region boundary change and potential alternatives. The uncertainty about the likely approach to region boundary change, including the potential for and timing of future boundary changes, may create a climate of uncertainty for existing and potential future market participants. This may have implications for their trading and investment decisions. This issue may also be the case for other potential changes to the congestion management regime.

Transparency is also an important feature of the congestion management regime. A high level of transparency around the likelihood of constraints, and the way in which NEMMCO will dispatch and settle the market when those constraints bind, is necessary to ensure participants can manage the associated trading risks. The following approaches are used in the current regime in order to promote transparency:

- the Rules go some way towards clarifying the broad approach to congestion management (eg. clause 3.8.1 of the Rules and Chapter 8 Part 8A derogation);
- NEMMCO provides information to participants about the likelihood of binding constraints and the associated price effects through the pre-dispatch information;
- NEMMCO publishes procedures that outline the way in which it will formulate constraints and manage negative settlements residues when they arise; and

36 Parer Report. KPMG, *Development of energy related financial markets, Report to Council of Australian Governments Energy Market Review, Final Report*, Sydney, September 2002

- NEMMCO issues market notices when new constraints are developed, for example as a result of network outages, and when non-routine constraints are invoked, for example as a result of the management of negative settlements residues.

14. Has the uncertainty regarding regulatory process and decisions created material risks for participants?
15. Do market participants face problems in managing risk due to a lack of transparency associated with the current approach to congestion management? If so, what are the nature and materiality of these problems?

4.5 Other issues

This Section has highlighted a range of potential issues with the current approach to congestion management, in line with the key themes for the Review. It may be that there are other issues with the current congestion management regime that should be considered by the Commission in the context of the Review. The Commission is keen to ensure that it understands all of the congestion management issues of concern to stakeholders, including the materiality of these concerns, so that it can design a regime that appropriately addresses these key issues.

16. Are there any additional issues with the current congestion management regime that should be considered as part of the Review? How can the materiality of these concerns be quantified?

5 Future options

For the purpose of inviting comments from stakeholders, this Section explores the tools that could form part of a comprehensive congestion management regime and the issues associated with the application of those tools as part of the package of congestion management arrangements in the NEM. It begins by describing the range of approaches for congestion management before discussing the proposed staged approach to congestion management. It then outlines, and invites comment, on a number of alternative approaches that may improve the current approach to congestion management in the NEM. The Commission does not consider the approaches identified in this Paper as exhaustive. The purpose of the discussion is to elicit comments from stakeholders on potential approaches to managing congestion in the NEM.

5.1 Approaches to congestion management

This Section summarises various international approaches to congestion management, and compares this to the approach adopted in the NEM. It then defines the key features of the current approach to congestion management, which will form the 'base case' for comparison with the congestion management implications of alternative approaches.

5.1.1 International approaches

The management of congestion in electricity markets around the world differs in three main ways:

- the extent to which wholesale market prices differ by location. Under a nodal pricing regime, different prices are determined for each transmission node while under a regional pricing regime the extent of locational pricing is more limited;
- the extent to which there are 'side payments' to generators outside of the spot market. Where the locational price does not fully incorporate congestion costs, it may be efficient to make 'side payments' outside the spot market, for example to pay a generator that is constrained-on due to intra-regional constraints. These payments are normally financed through an 'uplift charge' spread across market participants; and
- the nature of financial instruments which are supported by the surpluses from locational price differences, and how market participants gain access to those instruments. Where prices differ by location, this creates a settlement surplus which can be used to underpin financial instruments to hedge market participants against the price separation. Markets differ in the extent to which that instrument is firm or non-firm and whether participants have to purchase hedging instruments or receive them through some form of administrative allocation.

These elements of market design are inter-related. For example:

- the electricity market in Great Britain (BETTA) is effectively one zone, with no locational pricing. There is, therefore, a high level of side-payments and of uplift charges. There are no settlement surpluses from locational price separation, and so no use of instruments such as IRSRs or financial transmission rights (FTRs);[37]

[37] An FTR is a tradable instrument that can be used to allow market participants to hedge the spot price difference between two locations at which they buy and sell energy. In its simplest form an FTR confers on its holder the right to receive payment (or the obligation to pay) based on the locational price difference between two points for a defined volume of trade MWh. Importantly, FTRs do not confer any right to priority physical dispatch, and so are compatible with an open-access transmission regime. A defining characteristic of FTRs is that they are funded from the 'settlement surplus' that arises as a natural consequence of LMP. These surpluses are the economic rents on the transmission system that arise from electrical losses and congestion between different locations on the network.

- the NEM takes an intermediate position on locational pricing—prices are uniform within large regions, but can separate between them. Side-payments to constrained-on generators are capped, limiting the impact on charges to other market participants. Settlement surpluses from regional price separation are auctioned (rather than allocated) to provide a (non-firm) instrument to hedge against price separation; and

- the New Zealand electricity market has nodal pricing, which means that the need for side-payments are low. Settlement surpluses are not currently used to support hedges against price separation, and there have been concerns that this has reduced generators' willingness to write contracts at distant nodes, and so the level of competition. However, there has been attempts for more than a decade to develop FTRs and make them available to market participants.

Appendix 6 briefly summarises the approach to congestion management in a number of international markets, including Great Britain, New Zealand, Pennsylvania-New Jersey-Maryland (PJM) in the United States, Korea, Chile, Argentina and Ontario (Canada).

Alteration to one of these three key elements of market design therefore needs to ensure a consistent approach to other elements.

5.1.2 Current approach to congestion management

It is important that there is a clear and agreed reference point for this Review, against which potential improvements to the regime can be considered. For the purposes of this Review, it is assumed that this reference point or base case involves making no further changes to current arrangements other than to allow changes that are already in process. That is:

- regional pricing, with prices between regions separating when congestion affects inter-regional flows. The current regional structure is assumed to be the starting point for the Review;

- SRAs, to provide participants with a non-firm mechanism to manage inter-regional price separation;[38]

- boundary change, based on technical criteria currently in the Rules and assuming the moratorium currently in place is lifted;[39]

- no pricing of intra-regional constraints (for example through the use of CSP/CSCs);[40]

- NEMMCO completes its implementation of the fully optimised constraint form, so that a consistent approach to the formulation of constraints is in place; and

- that there is no explicit means of managing counter price flows (ie. NEMMCO intervention to manage counter price flows ceases), following expiry of the Chapter 8 Part 8 derogation under which NEMMCO currently limits interconnector flows to control negative residues.

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38 The characteristics of the existing IRSR units are assumed to remain unchanged, with the value of IRSR payments affected by negative settlements residues and reductions in the available capacity of the network.

39 That is, the processes and criteria currently in clause 3.5 of the National Electricity Rules are assumed to apply, in the absence of any rule changes being made in response to the MCE's reform of regional boundaries Rule change proposal to modify clause 3.5 of the National Electricity Rules (see Appendix 2).

40 The presence of hybrid constraints means that some network limits within regions can have an effect on price outcomes in the NEM.

17. Is this an appropriate characterisation of the current arrangements in the NEM for the purposes of assessing potential improvements to the congestion management regime?

5.2 A staged approach to congestion management

The terms of reference for this Review and the MCE's proposed boundary Rule change outline a proposal for a 'staged approach' to congestion management in the NEM. Under this staged approach:

- no action would be taken in response to minor or temporary congestion;
- a congestion management regime would be introduced in response to material congestion. The proposed CSP/CSC regime, discussed in more detail in Section 5.4, would introduce modified pricing for generators affected by a material constraint and might incorporate contracts, which protected their financial position. The arrangement would leave pricing for load unchanged;
- where congestion is both material and enduring, investment in transmission may be justified. This could where necessary be facilitated by the Commission invoking a LRPP process; and
- if the congestion persists, and no investment response is forthcoming, the Commission may undertake a review of whether the criteria for region boundary change are met, and if so initiate a boundary change. The boundary change would lead to changed pricing arrangements for load as well as generation.

This proposal is outlined in the terms of reference for this Review, the MCE's rule change request for region boundaries, the MCE Transmission Statement of May 2005 and in the CRA Report. The staged approach was intended to provide a mechanism to address transient or temporary constraints in the NEM without changing region boundaries.

5.2.1 Rationale for a staged approach

The Commission notes that the introduction of a staged approach to congestion management could represent a significant change in market design. It is important that any change of this significance is based on clear identification of the problems being addressed (within the framework of the NEM objective), confirmation that the approach taken is the most effective response and confirmation of the technical and commercial feasibility of the proposed change.

The Commission's consideration will be based on analytical work done to date on this issue, further analytical work undertaken by the Commission during this Review and submissions in response to this Issues Paper and any subsequent consultation.

18. Is the proposed 'staged approach' to congestion management an appropriate framework? Is it the most effective response to those problems? Is it technically and commercially feasible?

5.2.2 Need for a staged approach

One argument for a staged approach to congestion management, including an intermediate step prior to region boundary change, is that boundary change can result in high costs. It may require amendments to systems operated by market institutions and market participants. It is also likely to be disruptive to participant hedging arrangements. Many participants enter hedges of several years duration, which could be affected by a change to region boundaries.

A staged approach would enable a different approach to be taken to congestion which is material but short-lived. For example, in some cases, congestion could be material, but may be reduced or removed within a few years through transmission investment.

The case for a staged approach would be enhanced if it was clear that the NEM frequently has material, but short-lived, congestion problems. However, if most congestion problems are enduring, the benefits of an interim instrument would be less clear. Similarly, the case for a staged approach would be enhanced if it is clear the costs to market participants of an interim arrangement are lower than the costs associated with boundary change.

19. Has the NEM had material congestion problems which have not been enduring? Is it likely to do so in future?
20. Are the costs of an interim congestion regime (discussed in greater detail below) clearly lower than the costs associated with region boundary change?

5.2.3 Process for implementation

A staged approach to congestion management requires clear criteria and accountability for the implementation of various stages. This includes

- triggers or conditions for the introduction of various congestion management tools at each stage. For example, under the MCE proposed staged approach, a region boundary change would be introduced if a constraint was found to be material and enduring, no investment response was forthcoming and there was likely to be a material and enduring increase in economic efficiency above a defined level; and
- responsibility for monitoring the materiality of congestion, and so identifying when the conditions have been met. The appropriate location of these functions within the NEM institutions depends in part on the detailed design of any scheme. For example, the appropriate institution to introduce a congestion management tool might vary according to whether there are clear and agreed rules for the introduction of the tool, or whether this entails a degree of negotiation with affected parties.

21. What triggers should be considered for the introduction of various congestion management tools under a staged approach? Which institutions should be responsible for recommending and approving the introduction of congestion management tools at each stage?

5.3 Amendments to existing arrangements

This Section considers amendments or extensions to arrangements that exist within the context of the current Rules, including the potential for changes to the existing arrangements for:

- the region boundary change criteria, trigger and guidelines;
- firming up IRSRs;
- the formulation of constraints;
- the management of counter price flows;
- payments to constrained-on generators; and

- NSAs and NCAS.

5.3.1 Regional boundary change criteria, trigger and guidelines

Regional boundary change is a key tool for congestion management in the NEM. This Section considers the MCE boundary Rule change before discussing region boundary change in the context of a staged approach to congestion management.

5.3.1.1 MCE reform of regional boundaries Rule change proposal

As outlined in Section 4.2.1, while the original design of the NEM envisaged evolution of the region boundaries against criteria for boundary change provided in the Rules, this evolution has not taken place. The MCE has proposed a Rule change to replace the technical criteria and process currently articulated in the Rules. The proposal looks to implement a consistent and defined process to consider region boundary changes, including the creation of economically based, forward-looking region boundary change criteria. It is proposed that the Rule change would also cover matters such as the frequency and process for boundary change, including timings, thresholds and triggers. Appendix 2 describes this Rule change proposal in more detail.

The Commission is currently consulting on the MCE region boundary Rule change proposal. The Commission encourages interested stakeholders to comment on the appropriate criteria, process, and timing issues for boundary change in the context of that consultation. Issues the Commission anticipates stakeholders would address in their submissions to the Rule change proposal include:

- What are the appropriate economic criteria for assessing the benefit of changing the regional structure of the market? How should any thresholds on net efficiency improvements be set?
- What is the optimal process for considering region boundary changes?
- How material is the threat of potential 'gaming' of region boundary applications? What are the implications for the design of the optimal process?
- What are the implications of region boundary change for participant trading risk? To what extent could a change in risk be managed by introducing a delay between the announcement and implementation of a region boundary change? What sort of delay would be appropriate?

5.3.1.2 Region boundaries and the staged approach

The Commission notes submissions to the MCE region boundary Rule change proposal will address the role of region boundaries in managing congestion and its implications for boundary change criteria and process. In the context of this Review, the Commission is interested in stakeholder views on the appropriateness of a staged response to congestion management and the implications for the boundary change arrangements.

A key question for the criteria and process for region boundary change is whether region boundaries should be the primary means of handling transmission congestion or whether boundary change should be the last part of a staged response to congestion as suggested in the MCE's region boundary Rule change proposal. If boundary change were to be the primary response to congestion, it may be appropriate to have more frequent reviews and stricter thresholds and triggers for change than if boundary change were the 'last resort' to congestion as part of a staged response. In the latter case, less frequent reviews and less stringent criteria may be more reasonable. The Commission recognises the importance of ensuring consistency between the MCE Rule change proposal and the outcomes of this Review.

An additional question remains whether there is likely to be a net improvement in efficiency resulting from region boundary change when an interim congestion management regime is in place. The MCE proposal suggests that efficiency of dispatch would be the criterion for a boundary change. As discussed below in Section 5.4, the introduction of CSPs is intended to provide improved incentives for cost-reflective bidding, leading to improved efficiency of dispatch. The case for subsequent region boundary change would therefore appear to rely on a further gain to dispatch efficiency, over and above that already realised through the CSP.

22. What role should region boundary changes play in managing congestion, particularly in a staged response? How much emphasis should be placed on that role?
23. Is the economic boundary change criterion proposed in the MCE region boundary Rule change proposal consistent with the staged approach to congestion management? What further efficiency gains would be realised from region boundary change, after the introduction of an interim congestion management tool?

5.3.2 Firming up IRSRs

As discussed in Section 4.3.2 the IRSRs that accrue as a result of inter-regional price differences due to losses and congestion are made available to market participants through SRAs to facilitate inter-regional trade. These IRSR units are not a firm hedge. Some parties have expressed a concern that this lack of firmness may limit the extent of inter-regional trade.

There are a number of ways that IRSR units could be 'firmed-up', to offer participants a hedge that is less dependent on the available capacity of a particular interconnector. For example:

- the volume of IRSR units offered in SRAs could be reduced, with NEMMCO retaining any excess of positive settlements residues to fund firmer inter-regional products. Under this approach it may also be possible to offer a range of SRAs products, with varying degrees of firmness;
- the IRSRs could be shared across a number of constraints or interconnects. This is similar to the approach suggested by the Southern Generators Rule change proposal, and generalised in a submission to the Southern Generators' Rule change proposal.[41] The generalised proposal involves redesigning the allocation of the settlements residue to more closely reflect a constraint residue, rather than an interconnector residue; and
- the volume of IRSR products offered could be reduced, with TNSPs required to make up any shortfall in IRSRs due to a lack of availability on an interconnector. This would effectively involve the introduction of firm transmission rights for inter-regional trade—which would be a material change to the current arrangements in the NEM including the role and risk position of TNSPs.

Many of these changes would take the design of the IRSRs closer to that of the firm transmission rights. Alternatively, it may be optimal to leave the existing SRA arrangements in place, and supplement them with other congestion management tools. This may include, for example, altering the approach to counter price flow management or the introduction of CSCs as part of a CSP regime.

41 See Biggar, Daryl, *Management of Negative Settlement Residues in the Snowy Region: Comments on the Proposal by LYMMCO and Other Generators,* 9 February 2005 and Biggar, Daryl, *Managing Negative Settlement Residues on the Vic-Snowy Interconnector*, 20 May 2005

24. To what extent will firming-up IRSRs facilitate inter-regional trade? What is the best approach to firming up IRSRs and how would this work?

5.3.3 Constraint formulation

As discussed in Section 4.1, NEMMCO is progressively implementing a consistent approach to constraint formulation throughout the NEM. The consistent formulation was selected after consultation on a range of options, and is known as 'option 4'. This approach to constraint formulation has the desirable characteristics of enabling NEMMCO, as system operator, to control all the relevant variables in the constraint equation as part of the central dispatch process. This is consistent with the MCE's view expressed in its Statement on Transmission. Further, where generator offers reflect their true willingness to supply, an 'option 4' constraint formulation should lead to efficient dispatch and price signals for investment.

However, as discussed in Section 4.1 some problems can arise under an 'option 4' constraint formulation where intra-regional or hybrid constraints bind. This includes a weakening of the incentives for generators to bid at prices that reflect their opportunity cost and the potential for counter price flows.

It may be possible to address these problems by using an alternative form of constraint formulation. For example, moving some of the variables in the constraint equation to the RHS may remove the potential for counter price flows. However, there is no guarantee that such an approach would improve dispatch efficiency. Moreover, if an alternative form of constraint equation were adopted it would be necessary to take action to avoid any deterioration of system security, as discussed in Section 4.1. The benefits of avoiding negative settlements residues using an alternative constraint formulation therefore need to be offset against the cost of a fall in transmission utilisation and potentially the acceleration of transmission investment in the longer-term.

The 'option 4' approach to constraint formulation was selected after a detailed assessment of the alternatives and consultation with stakeholders. The Commission is keen to understand from stakeholders whether this debate should be reopened in the context of the Review. There may be other tools for promoting more cost reflective generator offers under an 'option 4' approach to constraint formulation—for example, a region boundary change or a CSP/CSC regime.

25. Is there a need to review the case for the 'option 4' constraint formulation approach in the context of this Review? If so, what would be advantages and disadvantages of moving away from an 'option 4' approach to constraint formulation?

5.3.4 Counter price flow management

As discussed in Section 4.2.2.2 counter price flows arise under the current arrangements for managing congestion in the NEM, and NEMMCO currently intervenes to manage those counter price flows.

The first question to consider in the context of the Review is the necessity of intervening to manage counter price flows. It may be that counter price flows either do not have significant impacts on inter-regional trading or are not likely to occur often enough or for long enough to justify any intervention. If no means were used to prevent or limit counter price flows, the impact on NEMMCO's financial and risk positions would need to be considered.

If active counter price flow management is deemed necessary, the question arises as to the appropriate form of intervention to manage counter price flows. This could include for example:

- directly limiting the flow on the relevant interconnector, which is the approach currently applied to manage northward counter price flows on the VIC-Snowy interconnector;
- using a different constraint formulation for the duration of the constraint; or
- reorientating the constraint so that the regional reference node is moved when particular constraints bind, to prevent the accumulation of counter price flows. This is the approach currently applied to manage southward counter price flows on the VIC-Snowy interconnector.

Alternatively, it may be that arrangements to firm up IRSRs (discussed in Section 5.3.2) could be implemented, removing the necessity to intervene to manage counter price flows.

26. What would be the effect of ceasing NEMMCO intervention to manage counter price flows? To what degree does this depend on other factors such as the region boundary criteria and process?
27. How should negative settlements residues be funded? Should the current process of offsetting negative residues with positive residues within the current billing week be continued or changed?

5.3.5 Constrained-on payments

As noted previously, an issue with the current arrangements is that generators may be dispatched even though their offers are above the regional reference price at which they will be settled. Some market participants have suggested that being 'constrained on' in this manner may encourage generators to make themselves unavailable for dispatch, which may cause dispatch to be less efficient than if those generators were available.

One option to address generators being constrained-on at prices below their offers may be to make constrained-on payments to them; that is, to pay generators an amount in addition to the regional reference price as compensation for being constrained-on. This additional amount could be determined in a number of ways. For example, it could be the difference between:

- the generator's offer price and the regional reference price; or
- a reasonable estimate of the generator's opportunity cost of generating and the regional reference price.

The former approach, which would result in generators earning their offers, may raise concerns about the exercise of market power by generators who know that they will be required to generate when a constraint binds. If the latter option were selected, some process would be necessary to determine reasonable costs, including for example assigning responsibility to a party to make the estimate. Potential parties could be the AER, AEMC, NEMMCO or an independent expert appointed by these parties. Other options for determining the level of constrained-on payments may also be available. An alternative way of viewing this is that high returns to constrained-on generators could surely attract new investment in generation, transmission, demand side participation or non-electricity alternatives to that area of the network, which would ultimately result in normal returns and a more efficient pattern of dispatch.

Regardless of how the quantum of constrained-on payments was determined, they would need to be funded in some manner. One option is for the payments to be funded by a levy on participants, similar to the ancillary services arrangements. There would need to be agreement on who would pay for the uplift. Uncertainty about the size and timing of the uplift may increase the complexity of risk management for market participants.

Alternatively, it may be preferable to address the issues of constrained-on payments through an alternative congestion management tool, such as a CSP (discussed in more detail in Section 5.4).

28. Are constrained-on payments an appropriate solution to generators being paid regional reference prices less than what they offer? If so, what principles should apply for determining the size of payments, who should apply them and how should they be funded?
29. Would the funding of constrained on payments be likely to introduce a material financial risk for participants making the payments? How could this risk be managed?

5.3.6 Network support agreements (NSAs) and network control ancillary services (NCAS) contracts

5.3.6.1 Network support agreements

NSAs, like the ones in Far north Queensland (see Appendix 3), help address transmission congestion without the need to invest in new transmission or generation assets. It may be that it is beneficial to consider extending the use of NSAs as a congestion management tool in the NEM. Consideration would need to be given to the arrangements for TNSPs to recover the costs of NSAs, including the timing of any pass through and the incentives to ensure network support costs are minimised. It will also be relevant to have regard to the way generators or demand side participants providing network support services would be bid into the NEM, and the resulting implications for dispatch and pricing signals. A key question is whether there are any inefficiencies in the existing arrangements that prevent the more widespread use of these contracts as a congestion management tool.

30. Would there be merit in extending the existing NSAs as a congestion management tool in the NEM? If so, how should such arrangements be implemented?

5.3.6.2 Network control ancillary services contracts

It may also be worthwhile to consider extending the use of contracts as a congestion management tool to the provision of NCAS. NCAS are primarily used to control voltage and power flow on the network and as such play a major role in maintaining system security and transmission capability. In some circumstances, the provision of NCAS can help substitute for network augmentation. While one means of implementing such agreements may be through a CSP/CSC regime (see below), another option may be through specific NCAS support contracts.

One question that arises with NCAS contracts is the appropriate counterparty. TNSPs currently enter into NSAs with generators and would also seem to be the natural counterparty for NCAS contracts. Indeed, the TNSPs are major providers of NCAS and are partly accountable for network availability under service performance schemes imposed by the AER. If TNSPs were to be entrusted with the role of NCAS contract counterparty, this would need to be reconciled with their incentives under these schemes. On the other hand, the provision of NCAS is currently tendered for by NEMMCO, as system operator, and funded through a market levy. The potential to transfer the responsibility for NCAS contracting to TNSPs was considered in the review of market and system operations, and highlighted as a potential option for the jurisdictions to consider.[42]

> 31. Should NCAS support contracts be used to enhance transmission network capability? If so, who should offer these contracts?
> 32. Is there merit in having TNSPs responsible for procurement of NCAS, rather than NEMMCO, so that NCAS forms a part of the Network Services? If so, how should this be arranged?
> 33. What would be the best way of funding NCAS payments and how should this be implemented?

5.4 Introduction of new arrangements – CSP/CSCs

This Section considers the use of constraint support pricing/constraint support contracts as a congestion management tool. It begins by discussing the proposal in more detail, before discussing elements of the design of the CSP/CSC arrangements requiring further work and analysis. It then considers the lessons that can be drawn from the partial trial of the CSP/CSC regime in the Snowy region.

5.4.1 The CSP/CSC mechanism

CSP/CSCs are a generator-only mechanism designed to overcome the dispatch inefficiencies created by certain network constraints. As discussed in Section 4.2.2, when a constraint within a region binds, the mismatch between dispatch and settlement can distort incentives for participants, reducing the efficiency of dispatch and pricing. The combination of CSPs and CSCs is designed to create economic incentives for a generator to act in a way that relieves a constraint.

When a constraint within a region binds, the CSP element of the mechanism adjusts the price earned by generators to reflect the congestion costs of those constraints and the generator's contribution to that congestion. This means that generators earn the marginal cost of supply at their local node instead of the price at their local regional reference node, which may be higher or lower than the price at that generator's node. By ensuring generators are paid according to the marginal cost of supply that their local node, CSPs at least partially mitigate the incentives for remote generators to bid in a way that is unrelated to their costs at times of binding constraints.

By settling a generator at its local node, rather than the regional reference node where other participants are settled, CSPs introduce an additional potential source of trading risk for participants. It is proposed that this is managed through the allocation of a CSC. CSCs provide a corresponding financial transmission right (FTR) to generators at times of constraint. Where a constraint binds, a CSC ensures that, for a specified volume or share of transmission capacity, the generator effectively receives the regional reference node price instead of the local price it receives as a result of the application of the CSP. Because a CSP can decrease or increase the price received by a generator, a CSC may either increase of decrease, respectively, the final price paid to a generator—in other words, offset the effect of the CSP. The presence of the CSC means that the generator has access to the regional reference node price for a share of its output, facilitating contract with other participants.

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42 Market and System Operation Review Committee, *System Security and System Operation Review, Report 1: System Operator Functions and Responsibilities*, March 2001

The intent is that generators affected by a CSP or CSC would make or receive payments from a defined congestion fund. If CSCs are non-firm the CSP/CSC regime is self-funding. However, creating firm CSCs means that the CSP/CSC regime is not self-funding.

The introduction of a CSP/CSC regime was a key recommendation of the CRA Report. The MCE conducted consultation on the CRA Report in late 2004. The submissions raised a number of key issues involving the CSP/CSC regime suggested by CRA, including the trigger for implementing a regime, the approach to the allocation of CSCs, the characteristics of CSCs including the approach to determining the size of the contract and the extent to which they would be tradeable on a secondary market and the transparency of the CSP/CSC regime relative to other forms of congestion management. Many of these issues are currently unresolved.

5.4.2 Designing the CSP/CSC arrangements

The consultation on the CRA Report highlighted that there are many elements of the proposed CSP/CSC regime that would require further development if it were to be implemented more broadly. This Section considers and invites comments on some of the key issues relating to further development of the CSP/CSC arrangements.

5.4.2.1 Allocation of CSCs

The impact on market participants of a CSP/CSC regime will differ, depending on whether or not the introduction of CSPs is combined with CSCs, which largely protect the financial position of incumbents. The use of CSCs is likely to have the effect of offsetting the impact of CSPs on the financial position of affected generators. This is likely to make it more acceptable to market participants to introduce CSPs rapidly in response to newly emerging congestion.

However, international experience (such as the problems associated with the introduction of FTRs in New Zealand) suggests that it may be challenging and time-consuming to develop and implement an approach to the allocation of financial transmission instruments like CSCs that is broadly supported by market participants. It is possible that CSCs could be allocated to incumbents, or alternatively could be made available via auction to interested parties. These approaches will have differing impacts on the financial position of affected generators and on the competitiveness of the NEM. The arrangements for the introduction of CSCs were a key concern during the MCE consultation on the CRA Report and the ACCC consultation on the introduction of the Snowy trial, even with only one participant directly affected.

34. Is the allocation of CSCs a necessary element of a CSP/CSC regime, or would it be practical to introduce CSPs without simultaneously allocating CSCs?
35. If CSCs are a necessary component, what is the optimal way to allocate CSCs? What effect will this have on the ability to introduce CSPs rapidly and flexibly?

5.4.2.2 Characteristics of CSCs

A key question for the design of CSCs is the extent to which they should be firm (that is a fixed MW amount independent of available transmission capacity), or non-firm (that is a function of available transmission capacity). The advantage of a firm right is that it would support participant contracting positions. The disadvantages of a firm right are:

- it may encourage a conservative approach to the allocation of CSCs to minimise the funding risk associated with the regime, which could hamper inter-regional trading;

- it would not be automatically self-funding, and so would require alternative funding. This would mean that the CSC counterparty (NEMMCO or the TNSP) was exposed to the risk of having to make additional payments under the regime; and
- there would be two instruments in the NEM—CSCs and IRSRs—with different characteristics and this could further complicate trading.

The introduction of another instrument with differing characteristics to IRSRs then raises a question about the interaction with the process of region boundary change. Introducing a boundary change might imply that parties who held CSCs (which might be allocated and might be firm) no longer held them. Instead they would have access to a non-firm instrument (IRSRs), which is auctioned rather than allocated, which may be less attractive to the participants concerned.

36. Is it important to the design of a congestion management regime whether or not CSCs are firm? If so, what issues should the AEMC consider in reaching a view on the appropriate nature of CSCs?
37. How should the process of region boundary change be coordinated with the allocation of CSCs under a staged approach to congestion management?

5.4.3 Lessons from the Snowy trial

A partial trial of CSP/CSC is currently in operation with respect to Tumut generation in the Snowy region. The trial is intended to address concerns that the Tumut generators faced inappropriate pricing signals at times when the constraint between Murray and Tumut in the Snowy region binds, creating inappropriate bidding incentives. Specifically, the trial was intended to address concerns that, at times when the Snowy intra-regional constraint binds and:

- flows through the Snowy region are northward, Tumut generators had limited incentive to generate to assist in meeting demand at times of high prices in NSW, because they were earning the relatively lower Snowy region price;
- flows through the Snowy region are southward Tumut generators had an incentive to maximise output to earn the relatively higher Snowy price, potentially sending counter price flows to NSW.

Under the trial, when the constraint between Murray and Tumut in the Snowy region binds, the price earned by the Tumut generators is adjusted by the CSP. This has the effect of ensuring Tumut generators earn a price similar to the NSW regional reference price, addressing the issues outlined above. The trial also involves:

- the allocation of CSCs to Snowy in respect of southbound flows only, so that Tumut generators receive the (higher) Snowy price on the first 550 MW of their output instead of the (lower) NSW price. The CSCs are non-firm in that they are linked to the availability of transmission capacity; and
- arrangements for the management of counter price flows, as discussed in Section 5.

The terms of reference for the Review require the Commission to consider the experience from the Snowy CSP/CSC trial. The Commission is currently considering how best to draw on that experience, to assist in decisions on both the merits of future use of CSP/CSCs, and any modifications required to the approach taken to their introduction and operation.

Assessing the trial's performance requires clarity on the issues that are being tested. The Commission has not determined a final basis for assessing the Snowy trial, but considers that assessment against the following issues would be helpful for decisions on the broader congestion management framework:

- *Efficiency*: the CSP/CSC framework is intended to change generator bidding behaviour in a way that will improve the overall efficiency of dispatch. How has the Snowy CSP/CSC trial changed generator bidding behaviour? Has this had an impact on the incidence of binding constraints? How has it affected prices in Snowy and neighbouring regions?
- *Flexibility*: the proposal for a staged approach to congestion management is intended to enable a more rapid and flexible response to constraints as they emerge, combined with infrequent boundary change. What lessons have been learned from the Snowy CSP/CSC trial on the ability to introduce such new arrangements rapidly and flexibly, in response to new congestion?
- *Disruption*: a further rationale for a staged approach to congestion management is that it is less disruptive than boundary change. What evidence is there from the Snowy trial of the difference in costs for market participants between introducing CSP/CSCs compared to a boundary change?
- *General application*: will findings from the Snowy trial be applicable across the NEM? If not, what particular features of the trial, or particular characteristics of the Snowy region, make the findings less applicable?
- *Scheme design*: what lessons have been learned from the Snowy trial on how to design, implement and operate CSP/CSCs.

> 38. How can the Commission best draw on the partial Snowy CSP/CSC trial to evaluate the costs and benefits of the use of CSP/CSCs? How can the Commission best draw on the Snowy CSP/CSC trial to consider modifications to the proposed design of CSPs and CSCs?

5.5 Alternative congestion management arrangements

The discussion above has considered a range of options for managing congestion in the NEM. It may be that there are other instruments that could form part of a comprehensive congestion management regime. The Commission is interested in understanding participant proposals for any alternative congestion management arrangements, including the nature of the arrangements, the way they would be implemented, the interaction with other congestion management arrangements and the likely effects on participant behaviour, pricing and dispatch in the short-term and investment in the longer-term. For example, as an alternative to full nodal pricing it could be possible to introduce an arrangement where generators are settled according to nodal prices, while customers continue to pay for electricity based on zonal prices. Similar arrangements have been implemented internationally, including for example in Singapore, and are being implemented in the Philippines.

> 39. Are there any additional congestion management tools that should be considered as part of this Review? How would these tools be implemented? How would they interact with other aspects of the congestion management regime? What would be the effect of such tools on participant behaviour and market outcomes?

5.6 Packaging of options

As noted in the previous Section, the options for managing transmission congestion are not necessarily perfect substitutes for one another. Some options may offer specific advantages and disadvantages over others, while some options may complement others, either at a point in time or over time, through a staged implementation process.

The Commission is conscious of the interaction between the congestion management options. This means that it is important to think about the way the various options should be combined and sequenced to form a comprehensive congestion management regime. While it may be possible to consider the merits of some options on a relatively stand alone basis, for example the potential to extend NCAS arrangements, the interaction between options does need to be carefully considered. For example, without an intermediate means of dealing with congestion pending region boundary change, it may be appropriate to have more frequent boundary reviews with shorter lead times than if the staged response approach proposed by the MCE were adopted. In assessing potential improvements to the current approach to congestion management in the NEM, the Commission will consider packages of options, recognising the interactions between the congestion management options.

40. Which, if any, of the congestion management issues identified in this paper could be considered on a stand-alone basis? Which issues need to be considered together to ensure a comprehensive and consistent congestion management regime?

The Commission will canvass responses from stakeholders about the extent and nature of congestion management issues in the NEM, and the relative merits of alternative approaches for managing congestion, before developing any approach to congestion management for assessment and further consultation.

Appendix 1 MCE terms of reference for the 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.

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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

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.

Appendix 2 Related Rule changes

The Rule changes currently before the Commission which it considers relate to this Review include:

1. Loop flows and negative residues Rule change from the Southern Generators and National Electricity Market Management Company (NEMMCO);
2. Snowy regional boundary Rule change from Snowy Hydro Limited;
3. Snowy regional boundary Rule change from Macquarie Generation;
4. Reform of Regional Boundaries Rule change from the MCE;
5. Economic Regulation of electricity transmission revenue and pricing Rules Rule change, being undertaken by the AEMC (the Chapter 6 Rule proposal);
6. Last Resort Planning Power Rule change from the MCE; and
7. Reform of the Regulatory Test principles Rule change from the MCE.

1 Loop flows and negative residues Rule change (Southern Generators and NEMMCO) [43]

The Southern Generators[44] and NEMMCO put forth this participant derogation to address the management of negative settlements residue on the interconnector between the Victorian and Snowy regions. Currently, when market conditions result in electricity flows moving from a high priced Victorian region to a lower priced Snowy region, NEMMCO intervenes in dispatch to prevent the further accumulation of negative inter-regional settlements residue.

The Southern Generators propose that one way to prevent NEMMCO from needing to intervene, and therefore impacting efficient generation dispatch, is to find a way to fund the accruing negative residues.[45] They propose to fund negative residues on the Vic-Snowy interconnector from positive settlements residues accrued on the Snowy-NSW interconnector. This would be possible by modifying the existing Chapter 8A Part 8 derogation (Network Constraint Formulation) which implements the Snowy CSP/CSC trial. Section 5.4.3 discusses the trial in more detail.

This derogation is due to expire on either: 31 July 2007; implementation of the first region boundary review by the AEMC; or as otherwise determined by the AEMC.

Consultation under s.95 of the NEL for this Rule change proposal closed on 10 February 2006. The Commission is currently considering submissions.

2 Snowy regional boundary Rule change (1) (Snowy Hydro Limited)

Snowy Hydro believes that the congestion issues currently prevalent in the Snowy region are significant enough to propose a one-off change to the Snowy region boundary. The proposed

43 Under Section 91(6) of the NEL, NEMMCO is required to be a proponent on any derogation that amends its functions.

44 The Southern Generators include: Loy Yang Marketing Company Pty. Ltd., Southern Hydro Pty. Ltd, International Power (Hazelwood, Synergen, Pelican Point, Loy Yang B and Valley Power), TRUenergy Pty. Ltd., NRG Flinders Pty. Ltd., and Hydro Tasmania.

45 The Commission is currently consulting on a proposal from NEMMCO to adjust the recovery of negative settlements residue. Submissions on that draft Rule determination are due by 3 March 2006.

new boundary would adjust the Snowy region boundary to relocate Upper and Lower Tumut generation in the NSW region, and Murray generation in the Victorian region, effectively abolishing the existing Snowy region.

This region boundary change would change the regional reference prices that Tumut and Murray generators would settle at. The view is that by changing the prices these generators receive, the incentives to constrain the transmission lines between them would decrease. The transmission line between Lower Tumut and Murray is the line that constrains the most during times of high demand in NSW, limiting the volume of electricity that can flow into NSW.

Snowy Hydro argues that the congestion in the region is such a significant problem that a boundary change is more appropriate than waiting until after the Commission considers the MCE's reform of regional boundary Rule change (described below) or completes its Congestion Management Review. Snowy proposes the implementation of the region boundary change from 1 August 2007, following the completion of the region's current congestion management trial (CSP/CSC trial).

The Rule change proposal is currently open for consultation under s.95 of the NEL. Submissions are due by 24 March 2006.

3 Snowy regional boundary Rule change (2) (Macquarie Generation)

Macquarie Generation has also proposed a region boundary change to address the intra-regional congestion problems in the Snowy region. It too believes that the congestion issues are a sufficient enough problem to consider a boundary change now, rather than after the Review.

Their proposal seeks to abolish the existing Snowy region and establish two new NEM regions in its place, one in Northern Victoria and one in South-West New South Wales. Macquarie Generation states that the new boundaries would separate significant and enduring points of transmission congestion, and would place the regional reference nodes, where the regional price is set, at major load centres.

Macquarie Generation also proposes the implementation of the region boundary changes from 1 August 2007, following the completion of the CSP/CSC trial.

This Rule change proposal is currently open for consultation under s.95 of the NEL. Submissions are due by 24 March 2006.

4 Reform of regional boundaries Rule change (MCE)

The MCE has submitted a Rule change proposal on the process and criteria for determining NEM region boundaries. The criteria in the current Rules are technically based and backward looking. The MCE proposes to replace those criteria with forward looking and economically based boundary criteria. The Commission would assess any application for a boundary change against these new criteria to determine whether the region change was likely to result in a material and enduring net economic benefit to the market.

The proposal suggests that Registered Market Participants or NEMMCO would put forth boundary change applications for consideration. The proposal also states that a region change application for a particular boundary could only be considered by the Commission every five years, unless market conditions around that boundary changed. This means that if the Commission considers an unsuccessful region boundary application, it would not consider any further applications to change a similar boundary within five years. If the Commission deemed a proposed change met the economic criteria, then the change would be implemented after at least three years' notice of the decision.

This Rule change proposal is currently open for first round consultation under s.95 of the NEL. Submissions are due by 10 March 2006.

5 Economic regulation of electricity transmission revenue and pricing Rules Rule change (AEMC) (the Chapter 6 Rule proposal)

The NEL requires the AEMC to amend the Rules governing the regulation of electricity transmission revenue and prices (Chapter 6 of the Rules) by 1 July 2006.

The Commission is undertaking the project in two phases: Revenue and Pricing. The Commission recently released a Rule Proposal for Revenue. In developing the Proposal, the Commission has sought a balanced regulatory framework, providing incentives for efficient network investment and operation. The framework is also designed to manage the potential for the exercise of market power by network operators while maintaining effective regulation with an appropriate requirement for clarity, transparency and accountability on the part of the Regulator.

The Commission has sought an extension to the implementation of the Rules relating to Pricing. The Pricing Rules will be amended by 1 January 2007, while the Revenue Rules will be amended by 1 July 2006. The next step in the Pricing phase will be the release of an Options Paper in March 2006.

The Commission is currently consulting under s.95 on the proposed Rules for Revenue. Submissions close on 20 March 2006. A Draft Determination is expected in April 2006.

6 Last Resort Planning Power Rule change (LRPP) (MCE)

The Commission is considering another MCE Rule change proposal which seeks to empower the Commission with a LRPP. This power would only be used if the normal market arrangements to provide efficient and timely incentives for the assessment of transmission investments failed. While not actually directing investment to take place, the Commission would direct TNSPs to undertake the Regulatory Test to assess the economic benefits of potential investments affecting major national flow paths. The results of the Regulatory Test application would be published to inform potential investors whether an economically viable project exists. This would provide valuable information for potential investors as to the viability of undertaking new investment.

The MCE's proposal explains that introducing a LRPP is part of a range of processes aimed at providing nationally (NEM–wide) consistent transmission planning arrangements. Such arrangements are key tools for establishing efficient network investment. At present there is no provision for an LRPP in the Rules.

Consultation under s.95 of the NEL for this Rule change proposal closed on 24 February 2006. The Commission is currently considering submissions.

7 Reform of the Regulatory Test principles Rule change (MCE)

Another Rule change proposal from the MCE seeks to reform the existing Regulatory Test for assessing new transmission investment. The MCE's intention with this proposal is to provide greater clarity for the application of the Regulatory Test and reduce the scope for dispute, which has proved problematic in the past.

The purpose of the Regulatory Test, developed by the AER under clause 5.6.5A of the Rules, is to evaluate proposed regulated transmission investment against all other reasonable network and non-network alternatives. The overarching objective of the Regulatory Test is to deliver economically efficient transmission investment within the NEM's network regulatory regime.

The Rule change proposal outlines a suite of principles that would provide minimum coverage guidelines for the AER to apply in promulgating the Regulatory Test. These principles include an economic and competition focus, currently underplayed in the existing Regulatory Test. These principles are intended to establish a streamlined process that helps to maximise the net economic benefits to the market.

Consultation under s.95 of the NEL for this Rule change proposal closed on 24 February 2006. The Commission is currently considering submissions.

8 Other Rule change proposals

As indicated in its draft Rule determination of 19 January 2006 on the recovery of negative inter-regional settlements residue, the Commission has decided to consider some of the issues raised in submissions to that proposed Rule change within the broader context of this Review. The broader issues discussed in the draft Rule determination included the:

- *Management of negative settlements residue accumulation.* NEMMCO currently intervenes in dispatch when significant counter-price flows are forecast or accruing. Submissions raised concerns with this practice, currently described in the Chapter 8A Part 8 Network Constraint Formulation derogation in the Rules. Submissions questioned the need for the intervention and the trigger for intervention.

- *Intra-billing week deduction of negative settlements residue.* Clause 3.6.5.4(i) of the Rules currently requires NEMMCO to deduct any accrued negative IRSR from positive IRSR values within the same billing period. Submissions stated that this practice reduced the value of SRA units as a hedging tool and removal of the practice would achieve a consistent negative residue funding approach across all timeframes

- *Discussion of the issue of negative residues.* Submissions expressed a need to discuss both the potential causes of negative residues and the procedure for NEMMCO to intervene because of insufficient funding mechanisms for negative residues.

Appendix 3 Network support agreements in the NEM

Far north Queensland provides an example of how the Rules allow a NSA to be used to manage transmission congestion so that supply reliability is maintained at points of the network for which there is no explicit price signal under the NEM's regional pricing structure (see Box 1).

Box 1: Network support agreements (NSA) in the NEM[46]

Powerlink is the TNSP that owns and operates Queensland's high voltage electricity transmission network. The regulatory regime and statutory requirements oblige Powerlink to maintain the safety, security and reliability of energy supply across it entire network.

Powerlink has entered into NSAs with generators to manage transmission constraints in the north of Queensland. Electricity demand in north Queensland and far north Queensland exceeds the capacity of transmission capacity into those areas at times of high demand.[47] This means that local generation is required to meet demand and maintain the transmission network in a secure operating state.

Powerlink has entered into NSAs with Enertrade (the entity responsible for trading Collinsville, Mt Stuart and Townsville Power Stations) and the Pioneer Sugar Mill. When power flows are approaching the capacity of transmission lines between central Queensland and north Queensland Powerlink instructs these local generators to generate under the terms of the contracts. This in turn prevents the constraint from binding.

In 2001, when there were no NSAs in place, the constraint bound for over 1000 hours in the last three months of the year.[48] However, since NSAs were signed in 2002 the incidence of the constraint binding has fallen significantly. For example, from October 2004 to March 2005 the constraint between central Queensland and north Queensland bound for only 15.5 hours. However, generation was dispatched under contract to avoid this constraint from binding for 365 hours (8% of the time).

Powerlink recovers the cost of the NSAs through its revenue cap and the resulting transmission use of system charges. Powerlink's NSAs are expected to cost $13-38 million in 2005/06 and $13-26 million in 2006/07. The agreements expire in 2007/08. A network augmentation has been recommended after 2008, following the application of the Regulatory Test in late 2005.[49]

46 Powerlink*, Annual Planning Report 2005,* Powerlink, Brisbane, 2005*;* Powerlink*, Request for Information Paper: Future Electricity Supply Requirements – North and Far North Queensland,* Powerlink, Brisbane, 7 May 2004

47 The north and far north Queensland area comprises all areas north of Broadsound and Dysart that take supply from the main Queensland electricity grid.

48 Enertrade, Annual Report 2001-02, p.13

49 Powerlink, *Recommendation to Address Forecast Reliability of Supply Requirements in 2007-2010, North and Far North Queensland Final Report*, 29 November 2005, p.5

Appendix 4 Types of constraints

This appendix provides additional details on three types of constraints:

- Pure intra-regional;
- Pure inter-regional;
- Hybrid;

and the effects each has on regional reference prices. For further discussion of trans-regional constraints and their pricing impacts, see the CRA report, *NEM Interconnector Congestion: Dealing with Interconnector Interactions*.[50]

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 one region. If a binding pure intra-regional constraint affects power transfers to and from the reference node, then the regional reference price will reflect the impact of the constraint binding. The price at the reference node will not be affected in any way if a binding pure intra-regional constraint does not affect power transfers to and from the reference node. These concepts are illustrated below. All examples assume no network losses and that each generator offers all its capacity at the offer price indicated.

Pure intra-regional constraint that affects the regional reference price

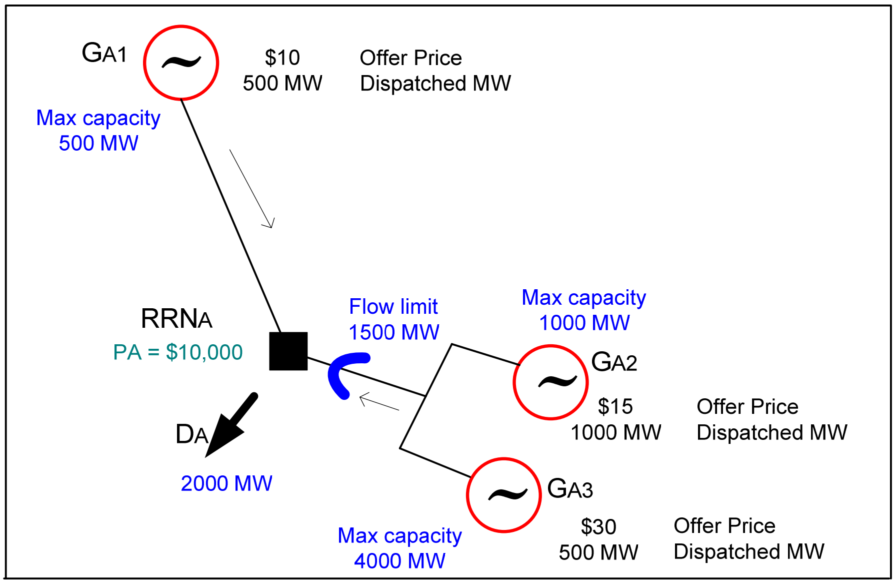
A pure intra-regional constraint binds in such a way that power flows to the regional reference node are affected. In order to balance supply with demand at the reference node, either additional energy is required or demand must be reduced. The incremental cost of procuring additional supplies of energy at the reference node as a direct result of the constraint binding is the congestion cost of the constraint. This congestion cost is reflected in the regional reference price. In Figure 1, there is no way of increasing generation to meet a 1 MW increase in load at the reference node because G_{A1} is at maximum output and the 1500 MW transmission limit restricts additional output from G_{A3}, so in the absence of any demand-side bids, the marginal price at the reference node is set by VoLL, $10,000/MWh. It can be shown that the marginal economic cost of the congestion equals $9970/MWh.

If this flow limit persisted over time, then the congestion costs implicit in the reference node price could provide incentives for economically efficient investments to:

- upgrade the transmission line from G_{A3} and G_{A2} to the reference node;
- increase the amount of generation capacity located on the other side of the constraint, which has unrestricted access to the reference node price; and
- reduce demand at the reference node through demand-side management.

[50] CRA, *NEM Interconnector Congestion: Dealing with Interconnector Interactions*, Report to NEMMCO, Wellington, 2003. Available at http://www.mce.gov.au/assets/documents/mceinternet/InterconnectorInteractions20041123171938%2Epdf

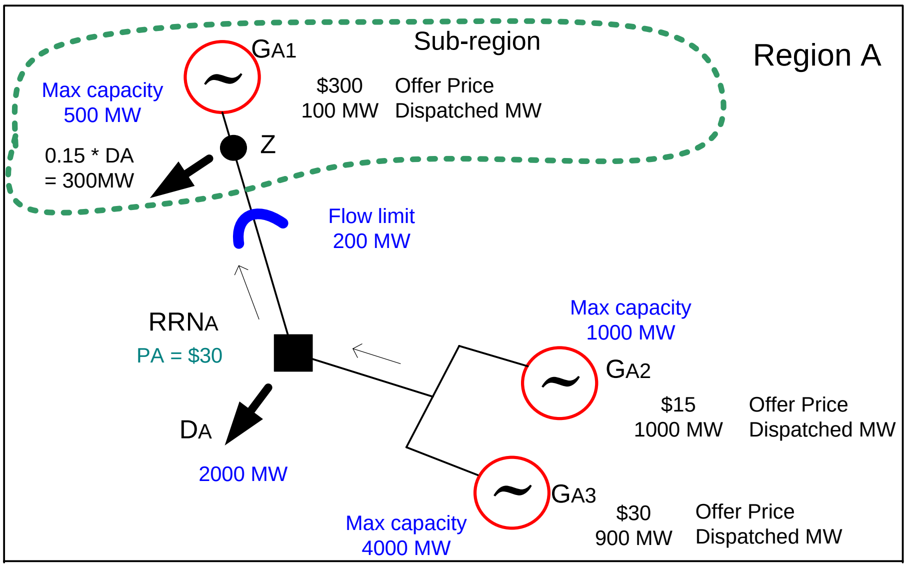
Figure 1: Pure intra-regional constraint that affects the regional reference price



Pure intra-regional constraint with no impact on regional reference price

Figure 2 illustrates the case of a pure intra-regional constraint binding that has no effect on the regional reference price. In Figure 2, total demand at the reference node is 2000 MW but fifteen per cent of this load (ie., 300MW) occurs physically in the sub-region containing node Z. Incremental demand at the reference node can be met by G_{A3}, at a price of $30, which sets the regional reference price. At that price, G_{A1} would not expect to be dispatched based on its offer price of $300. However, in order to meet the 300MW 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 can not be met because the 200MW flow limit is binding.[51] 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 regional reference node.

Figure 2: Pure intra-regional constraint with no impact on regional reference price



[51] Although all load is notionally treated as being at the reference node, 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 reference nodes.

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 regional price is below the price at which it is prepared to offer its capacity.

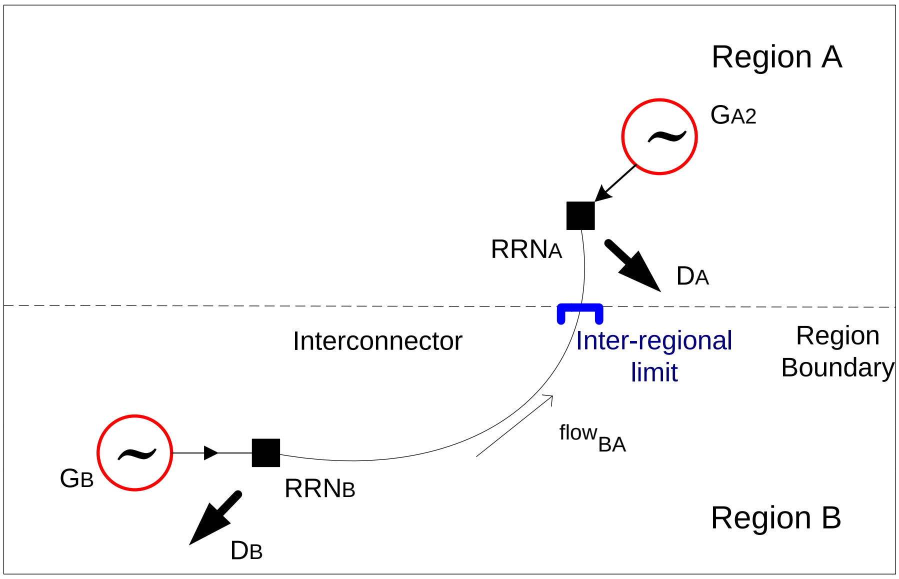
These pricing arrangements can provide incentives for:

- G_{A1} to declare itself unavailable, so that it can be compensated at a higher price than the reference price;[52]
- The local TNSP and G_{A1} to enter into a NSA.

2 Pure inter-regional constraints

A pure inter-regional constraint is one in which the ability to transfer power between regional reference nodes is unaffected by power flows through a constrained element within a region, but only affected by the (security constrained) physical capabilities of the interconnector itself (see Figure 3 below).

Figure 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.

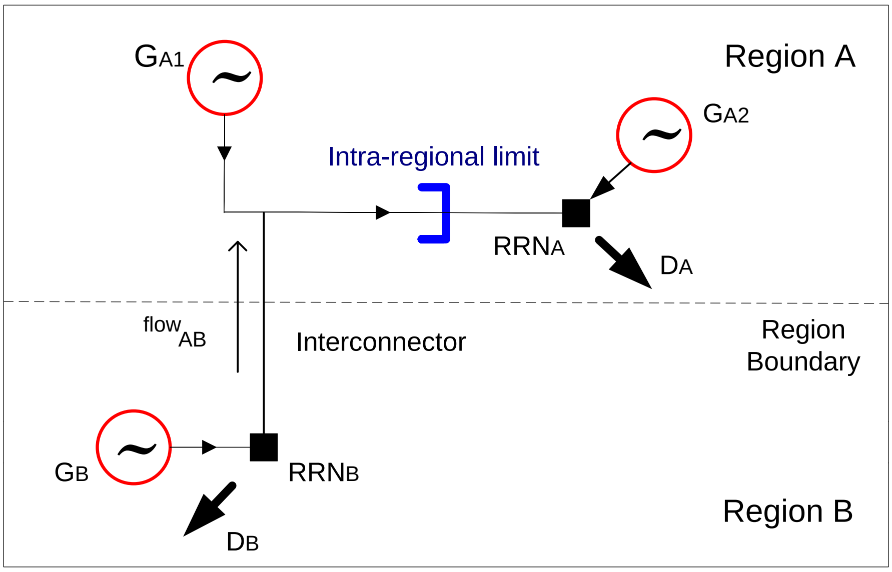
When there is a pure inter-regional constraint it is usually necessary for additional generation in the importing region to be dispatched to meet load in that region, even though it may have a higher offer price than generators located in the exporting region. Under these circumstances the price in the 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.

52 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.

3 Hybrid intra-regional and inter-regional constraints

With 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. Figure 4 illustrates this. In Figure 4 there is a network limit between generator G_{A1} and the Region A regional reference node (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 reference node is unaffected by the constraint. Given that G_{A2} will be the marginal supplier at the reference node, under the NEM Rules it will set the price at RRN_A. The price at Reference Node 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 4: Hybrid constraint



The relative locations of the point of congestion, the reference node, generation, and the interconnector all play a role in determining the extent to which the congestion affects the regional reference prices in the region with the constraint and the regions linked by the interconnector.

Appendix 5 Counter-price flows and negative settlements residues

This Appendix discusses the causes of counter-price flows and the consequences such flows can have on the economic efficiency of dispatch. Counter-price flows, together with any intervention by NEMMCO to manage such flows, can adversely affect the ability of market participants to manage financial risks associated with trading between regions.

1 Managing counter price flows

Counter-price flows occur when the central dispatch process results in electricity flows from a high priced location to a low priced location, resulting in an accrual of negative settlements residues between those locations.

Counter-price flows consistent with efficient dispatch can emerge as a result of:

- binding constraints on a radial network; or
- a binding constraint on part of a transmission loop with different pricing nodes located around the loop.

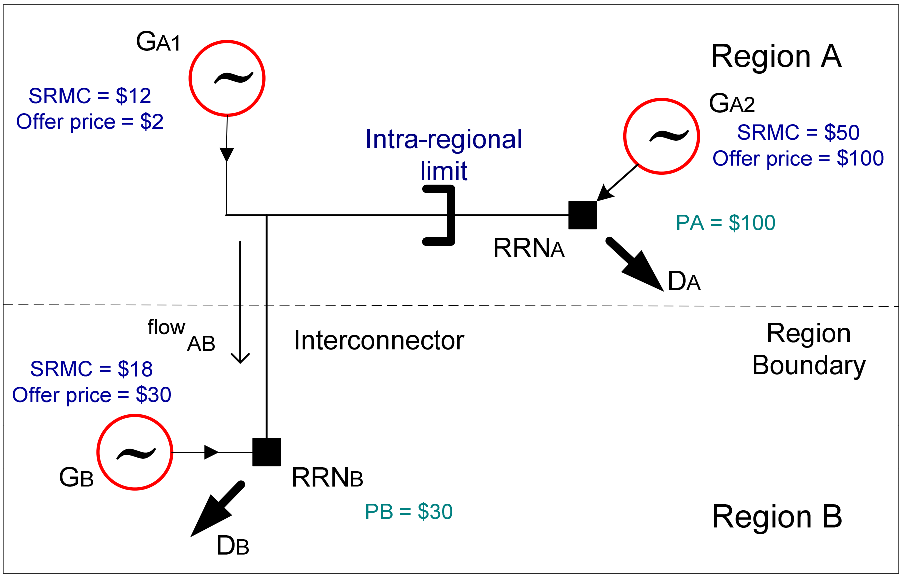
Each of these possibilities is discussed in more detail below. All examples assume no network losses and that each generator offers all its capacity at the offer price indicated.

2 Counter-price flows on a radial network

When there is a binding constraint on a radial network with regional pricing, counter-price flows can emerge as a result of the inconsistency between dispatch outcomes and the price at which some participants are settled. This inconsistency arises because under the NEM's dispatch and pricing rules, generators that are constrained off have a limited effect on the local regional reference price. This can be demonstrated by way of a simple example on a radial network (see Figure 5).

Figure 5 compares the optimal dispatch outcomes based on bids and offers to the economically efficient dispatch that would arise if the market were dispatched on the basis of short run marginal costs (SRMC). The purpose of this comparison is to demonstrate that settlement based on regional reference prices can sometimes encourage bidding behaviour that results in a market equilibrium that uses a combination of generation with a higher underlying cost than would be the case if bids and offers reflected underlying SRMC.

Figure 5: Economically efficient counter-price flow in a radical network with a hybrid constraint and regional pricing.



The figure assumes there is a constraint in Region A that limits the flow on the interconnector between Region B to Region A. The constraint also limits generator G_{A1}'s ability to deliver power to Region Reference Node A (RRN_A). It is assumed that there is a generator (G_{A2}) located at RRN_A that is sufficiently large to meet any increase in demand at that node, despite the constraint binding. This generator G_{A2} will therefore be the marginal generator that sets the price at RRN_A, based on its offer price ($100/MWh). In Region B, demand at the reference node can be met from generation by G_B and imports from Region A along the interconnector. Assume that G_B is the marginal generator whose offer price sets the Regional Reference Price (RRP_B) at $30/MWh. Under the NEM's regional settlement, all of G_{A1}'s output will be paid the RRP_A price, $100/MWh. This creates the incentive for G_{A1} to maximise its dispatch volume by lowering its bid price to, perhaps, $2/MWh, which is below its SRMC of $12/MWh. In this case, least-cost dispatch based on bids and offers will result in G_{A1} being dispatched up to the point where its output is limited by the interconnector flow limit from Region A to Region B and the hybrid constraint affecting transfers through to RRN_A. The prevailing flow of power will be from Region A to Region B, which is counter to the price difference ($RRN_A > RRN_B$).

This counter-price flow results in the accumulation of negative inter-regional settlements residue. In this case, the negative settlements residue arises from dispatching the least-cost optimal outcome, based on bids and offers *and* consistent with least-cost economic dispatch based on SRMC. An objective of the market design is to drive dispatch towards that which one would expect if underlying costs were used. In this case, if dispatch were based on the underlying SRMC with everything else unchanged, there would be no change in the pattern of dispatch—each generator would be dispatched to the same MW volume as before, but the prices at the reference nodes would be lower, RRP_A = $30/MWh and RRP_B = $18/MWh. In this case, four conclusions can be drawn:

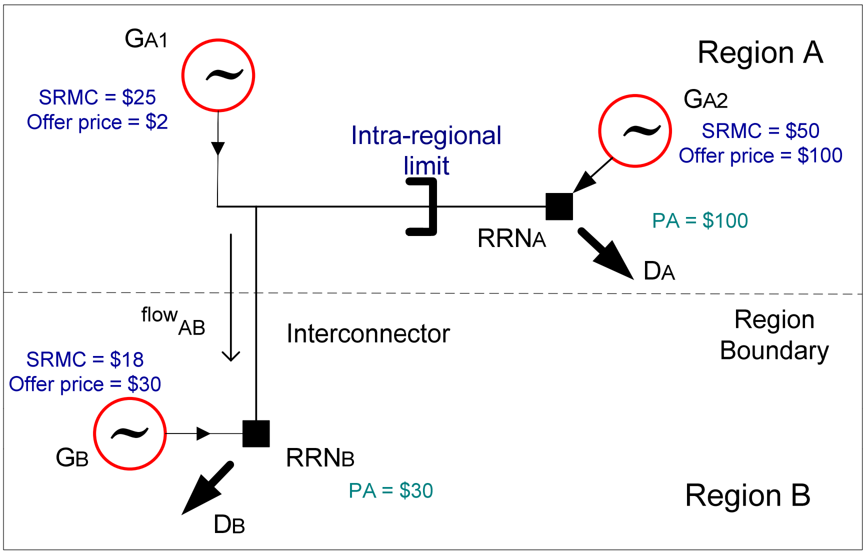
- the regional pricing structure of the market creates incentives for G_{A1} to offer below its underlying SRMC in order to maximise the revenue it receives from settlements based on RRP_A;
- dispatch based on bids and offers results in accrual of a negative settlements residue on the interconnector;

- the physical dispatch outcomes, including the power flows that give rise to the negative settlements, would be identical if dispatch were based on SRMC—the benchmark for measuring the economic efficiency of the market. The pricing outcomes will, however be different; and
- the negative residues are consistent with economically efficient dispatch based on SRMC.

Figure 6 is identical to Figure 5 except that the SRMC of G_{A1} is now $25/MWh. In this case, the dispatch outcomes based on bids and offers would be unchanged from Figure 5. However, in Figure 5:

- the dispatch outcomes based on bids and offers will be inconsistent with economically efficient dispatch based on SRMC, because GA1 is dispatched to higher level based on its offer price than it would expect under SRMC-based dispatch;
- the incentives created by regional pricing for GA1 to offer below its underlying SRMC contribute to a reduction in economic efficiency relative to SRMC-based dispatch and pricing; and
- the negative residues are arising from dispatch based on bids and offers are *not* consistent with economically efficient dispatch based on SRMC.

Figure 6: Economically inefficient counter-price flow in a radical network with a hybrid constraint and regional pricing.



3 Counter-price flows on a looped network

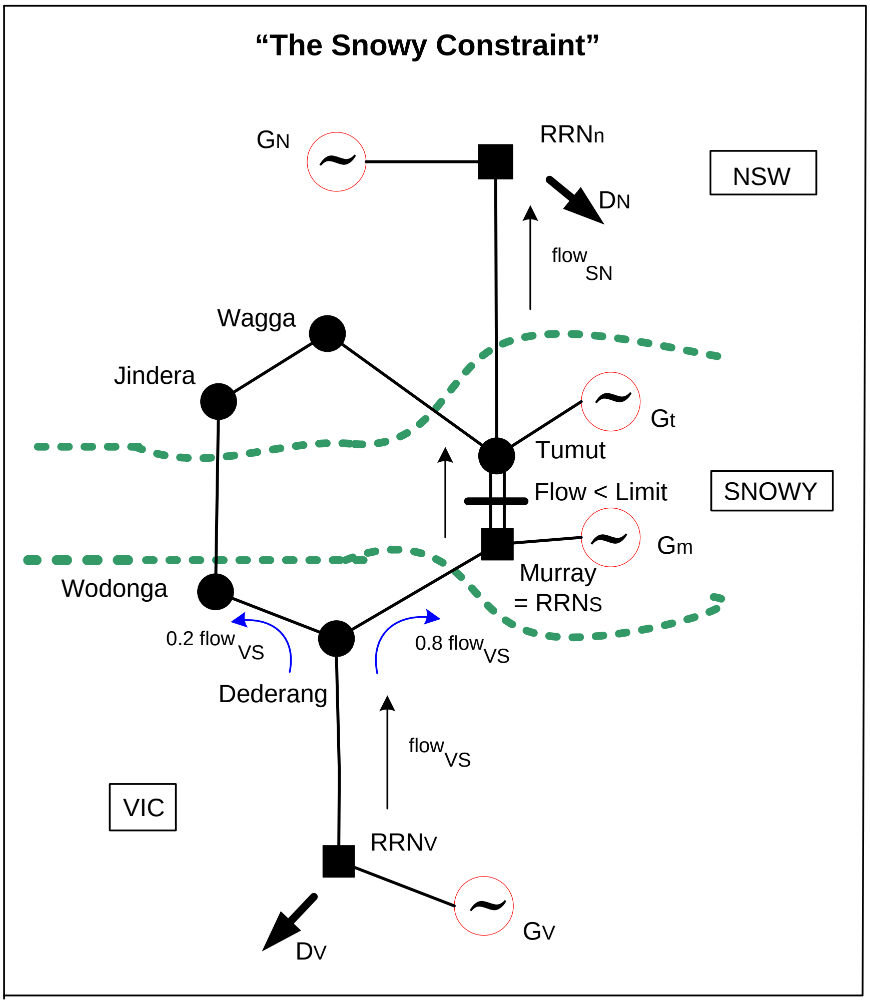
A constraint on a segment of physical loop in an alternating current (AC) transmission network can create economically efficient counter-price flows on one or more locations around the loop.[53] The current regional structure deliberately avoids loops being created as part of the regional structure. Instead, regions are arranged in a radial manner. However, there are a number of physical loops in the system, for which the price effects of congestion on one part of the loop are not fully reflected in the regional reference price.

53 This is often referred to as the "spring washer effect". See E. G. Read and B. J. Ring, *Dispatch Based Pricing: Behaviour of Nodal Power Prices*, In A. J. Turner (editor), *Dispatch Based Pricing*, Trans Power (NZ) Ltd, Wellington, 1995

The only AC transmission loop that spans several regions is the area around the Snowy region. The effect of one element of this loop reaching its flow limit, combined with the NEM's regional pricing structure, can result in economically efficient counter-price flows. These counter-price flows can result in the accrual of substantial negative IRSRs.

Figure 7 shows the looped network in and around the Snowy region of the NEM. One arm of the loop links the VIC reference node—via Dederang, Wodonga, Jindera and Wagga—to the NSW reference node. The other arm of the loop links the Dederang, Murray and Tumut transmission connection points. Power flows around the loop are determined by the relative impedance of the different paths around the loop. For example, if power is injected into the loop at Dederang, it splits in two and travels around the two alternative paths, towards the NSW reference node. There is an intra-regional constraint within the Snowy region between the Murray and Tumut connection points. If flows between Murray and Tumut reach their limit, the lines become constrained. This constraint can affect prices in the NSW, Snowy and VIC regions because it affects flows on the Snowy-NSW and Vic-Snowy interconnectors. In these circumstances, there may be counter-price flows that are consistent with efficient economic dispatch. This can be illustrated assuming the prevailing trans-regional flow is from VIC towards NSW.[54]

Figure 7: Snowy region network topology



[54] It is also possible to illustrate this when flow is in the reverse direction – from NSW to VIC.

When there are northward flows from Victoria into the Snowy region, and the intra-regional constraint between Murray and Tumut binds, the location on the loop where the value of generation is lowest is Murray. This is because an increase in 1MW in output at Murray increases congestion on the constrained link by more than power injected anywhere else on the loop (including the Victorian RRN). Since Murray is also the location of the regional reference node for the Snowy region this results in the Snowy regional price being lower than the Victorian reference price, leading to negative settlements residues on the VIC-Snowy directional interconnector.

In this case, the Murray regional reference price correctly reflects the economic costs of congestion at that point and provides a signal to reduce generation at Murray. This is because a reduction in generation at Murray provides the greatest relief to the constraint, relative to the reductions in generation anywhere else on the loop. A reduction in the level of generation at Murray would contribute to a reduction in the total costs of meeting demand across the network.

However, since generation at Tumut receives the Murray price under the NEM's settlement rules, it might not have any incentive to generate at a level that would relieve the constraint. In the extreme, Tumut generation might not generate at all if the Murray price is well below the opportunity cost of energy at Tumut (ie. the water value at Tumut). Since Tumut does not receive a price that reflects the value of its generation to the market, it may produce an inefficiently low level of output from a dispatch perspective.

The existing Rules and regional pricing structure potentially adversely affect the economic efficiency of dispatch around this loop in three ways:

1. the regional pricing structure does not include prices for all points around the loop. This deprives the market of the locational price signals that would enable them to reduce the level of congestion in the most economically efficient manner via the dispatch process;
2. the mis-match between the price received by generation at Tumut, its offer price and SRMC; and
3. the Rules allow intervention by NEMMCO to limit the value of negative IRSRs. This intervention can curtail the level of flows from VIC to SNOWY, and raise the total cost of meeting demand across the NEM, based on bids and offers.

Under the Rules, procedures have been developed which allow NEMMCO to manage counter price flows in order to limit the accumulation of negative settlements residues. These procedures have been put in place because there is as yet no robust means of funding negative IRSRs.

In general terms counter price flows are managed by introducing an additional constraint into the central dispatch process.[55] This constraint directly limits the flow on the notional interconnector to the extent necessary to prevent further accumulation of negative residues.[56] NEMMCO's procedures require it to intervene each time negative residues over the period of counter price flows are forecast to reach, or actually reach, an accumulated value of $6,000.[57] The interconnector flow limitations are removed when NEMMCO is satisfied that this will not result in further counter price flows.

As these actions essentially constitute an intervention in the optimal dispatch process, it is important that there is transparency in the way that they are implemented.

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55 Another option for limiting the accumulation of negative IRSRs involves changing the location of the regional reference node by re-orienting constraints to an adjoining connection point. This option was considered in by NEMMCO in 2005, but rejected after public consultation. See NEMMCO, *Revision to Procedures for Management of Negative Residues – Final Determination*, NEMMCO, Melbourne, 20 September 2005.

56 The interconnector flow is adjusted gradually, or ramped at a rate no greater than that which applies for a planned outage.

57 NEMMCO, SO_OP3705, September 2005, p.28

For the purpose of evaluating alternative approaches to congestion management it will be assumed that the current approach to congestion management includes the management of negative settlements residues by directly limiting the flow on the interconnector, as outlined above.

Appendix 6 Summary of international approaches

Table 3: International summary on approaches to electricity market design and congestion management

Market	Market structure and hedging instruments	Dispatch and constraint model	Approach to settlement/pricing and congestion management	Changes to regional boundaries and market design
Pennsylvania –New Jersey –Maryland Market (USA)	Full nodal pricing market covering Pennsylvania, New Jersey and Maryland in the USA. There are over two thousand nodes, but most transactions are referenced to a small set of 'trading hubs'. PJM has both day-ahead and real-time balancing markets, both based on nodal pricing. It also has separate markets for regulation and spinning reserve. PJM also imposes capacity obligations on load-serving entities (suppliers), with capacity credits traded in a market. PJM allocates FTRs to buyers of firm transmission services. FTRs provide their holders with a right to a proportionate share of the annual congestion charges associated with the points of receipt and delivery designated in their service agreements. FTRs are not completely firm, in that there are some (limited) exceptions to full payment. Other ('non-firm') customers may either choose to pay congestion charges as they arise in the day-ahead market or be curtailed. These customers must also pay transmission charges, but at a lower rate than firm customers. FTRs may produce obligations to pay if counter-price flows occur. Since 2003, FTR options have been available, which only carry a positive value (ie. cannot impose an obligation to pay).	PJM uses a set of computer programs known as the PJM Two-settlement Technical Software, which performs security-constrained unit commitment (RSC) and economic dispatch (SPD). Both these models use generic constraints produced by the STNET powerflow model, which contains a full representation of the underlying physical network.	Transmission customers may submit fixed, dispatchable or 'up to' congestion bid bilateral transaction schedules into the day-ahead market and may specify whether they are willing to pay congestion charges or wish to be curtailed if congestion occurs in the real-time balancing market. All purchases and sales in the day-ahead market are settled at the day-ahead prices. The day-ahead scheduling process incorporates reliability and reserve requirements.	In 1998, following repeated intervention by the system operator to manage congestion in a zonal pricing market, PJM switched to a nodal pricing design. Boundary change is therefore no longer applicable.
Britain	Real time single node ex-post net market covering England, Wales and Scotland. Participants submit nominations of supply and demand side requirements. BETTA is concerned with managing and pricing any imbalances between these nominations and actual	NG operates the system using a full network model.	In the energy market transmission congestion is not priced. There are no locational prices and the cost of managing the resultant congestion is	Fundamental market design change from ex-ante gross pool (established in 1990) to

Market	Market structure and hedging instruments	Dispatch and constraint model	Approach to settlement/pricing and congestion management	Changes to regional boundaries and market design
	supply and demand on a half-hourly basis. National Grid (NG) (the system operator) manages any imbalances through the balancing mechanism (BM, which covers only about 2% of total electricity traded), by accepting a bid or offer to increase or decrease generation (or demand). The BM is also used to resolve transmission constraints and maintain the quality and security of supply. Participation in the BM is voluntary and participants are paid for their response on a pay-as-bid basis. The cost of managing these imbalances is recovered via the imbalance settlement process (ISP), which is by managed by Elexon (the market operator). In this process participants are charged for short and long positions relative to their nominations.	The BM is dispatched on a locational basis to ensure the system is maintained in balance. NG manages congestion by calling bids and offers through the BM as required. NG hedges its exposure to the imbalance prices by entering into contracts with participants (which specify the offers that the generators will submit to the balancing market at times of constraint).	shared through the balancing services use of system (BSUOS) charges on a $/MWh basis. NG is incentivised under the regulatory arrangements to minimise these costs. Constraints and losses are taken into account in the way NG manages the system in real time using bids and offers from the BM (supported by longer term contracts with specific generators). However, the costs of these constraints and losses are then removed from the prices used for the ISP (which are based on BM bids and offers called) via agreed systems and algorithms. The ISP sets national (non-location specific) system buying and selling prices.	net arrangements based on ex-post, real time net market (established in 2001, and extended to include Scotland in 2005). Mechanism for managing constraints – calling bids and offers from participants (and entering into contracts with generators to hedge the cost of this) and setting energy market prices that do not reflect the cost of congestion has not changed substantially with design change.
New Zealand	Real time ex post nodal market, with about 250 nodes. NZ electricity market consists of an energy market and a co-optimised instantaneous reserves market, akin to the NEM FCAS market. The market is cleared by stacking supply offers and demand bids; the clearing price is set by the marginal generator. The System Operator provides scheduling and dispatch services under the EGRs (Electricity Governance Rules). There are no FTRs in place but they have been under consideration. Most transactions are referenced to two 'trading hub' nodes.	The New Zealand power system is modelled for the purposes of Scheduling, Pricing, and Dispatch (hence the term SPD Model) as a national set of nodes and branches connecting those nodes. When unconstrained dispatch does not allow the System Operator's security policies to be met - for example, if transmission assets are expected to be	A price for wholesale electricity is posted at around 250 market nodes for each half-hour trading period. Spot prices reflect transmission losses and grid constraints. The NZ electricity market traditionally uses three key price calculations – a forecast price, a dispatch price and a final price. A market clearing price is determined for every node in the New Zealand transmission grid. Thereby any possible congestion in the grid is automatically appropriately incorporated in the market clearing	The new arrangements introduced in December 2003 terminated the former NZEM and MARIA (metering and reconciliation information agreement) as part of broader industry and institutional reforms replacing self-regulation, including the establishment of the Electricity Commission. Industry has view that

Market	Market structure and hedging instruments	Dispatch and constraint model	Approach to settlement/pricing and congestion management	Changes to regional boundaries and market design
		operated beyond rated short-term capability after any defined contingent event - then a security constraint is applied in SPD. Constraints are represented by equations in SPD. A list of both permanent and temporary (outage) security constraints (including equations) is published by close of business every Monday.	price.	there are too many nodes and that number of nodes was engineering driven and not necessarily practical.
Korea (KPX)	Day ahead spot market, with ex post pricing. Cost based pool with both energy and capacity payments. The market price is composed of the marginal price (that differs for base load and non-base load plant) and a capacity payment. Both fixed (capacity payment) and variable costs for each generating unit are determined monthly by a Generation Cost Assessment Committee (GCAC).	The market and system operator (KPX) runs a scheduler system to establish a Price Setting Schedule (PSS) and calculate the marginal price a day ahead according to the demand forecast of the trading day. An operation schedule considering various fuel and transmission constraints is then published.	Congestion and generation constraints such as fuel limitations and district heat supply are not considered in setting the system marginal price. Constraints in the transmission grid are handled by re-dispatch and balancing arrangement. Congestion costs (including losses) are recovered through an uplift.	Original market development plans contemplated a move to a bid driven (rather than cost based) system marginal price determination in 2004, but this has been delayed. It is expected that the capacity payment would be abolished when the new arrangements are implemented.
Chile	Nodally priced pool involving two main regional markets (not interconnected):	Dispatch is undertaken on an economic merit order, pre-programmed basis for	Cost based pool with both energy and capacity payments. At each node there is a price for the energy and a price for	Wholesale design changes, including the establishment of a power

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	• SIC (Sth & Central); and • SING (Nth). Two market systems operate: • prices for the regulated market (73% of demand) are fixed for six-monthly periods; and • prices for the unregulated market are determined through bilateral negotiations.	the entire system in hourly units. Generators are required to declare availability and operating cost for every hour.	the capacity. Energy spot prices are set at each node of the interconnected system and are based on the weighted average of short run marginal costs (SRMC) of generation for the entire system optimized over a 12- or 48-month horizon (which accounts for reservoir levels, plant availability, thermal plant operating costs, new capacity and rationing). A 50-MW gas turbine increment is used to set the capacity component of the price, and transmission losses are incorporated.	exchange and net market, were considered in 2000 and abandoned. There have been concerns expressed over the effectiveness of the transmission arrangements for encouraging transmission investment, which in turn has implications for the incidence of congestion. Legislation was passed in 2004 to clarify the transmission pricing arrangements in an attempt to address this problem.
Argentina	Hourly nodally priced market. Two regional markets (not interconnected): • MEM – wholesale market covering 93% of demand; and • MEMSP – far south market. Bid based pool with both energy and capacity payments, with bids constrained to costs.	A single market node is used to coordinate dispatch and pricing on an hourly basis by the market operator, CAMMESA. The system is operated and the energy price at each node is calculated using a load flow programme.	Nodal prices are calculated for each node in the system to reflect the cost of losses and congestion. At each node there is a price for the energy (based on the marginal cost of generation) and a price for the capacity. Bids cannot exceed 115% of the actual fuel costs incurred by generators in their fuel purchases. Fuel costs are subject to verification by CAMMESA. The increase in variable transmission cost arising from congestion is	There have been concerns expressed over the effectiveness of the transmission arrangements for encouraging transmission investment, which in turn has implications for the incidence of congestion.

Market	Market structure and hedging instruments	Dispatch and constraint model	Approach to settlement/pricing and congestion management	Changes to regional boundaries and market design
			accumulated in a special account, known as the Expansion Account (called Exceed Fund). The funds accumulated as a result of congestion are identified with a particular network corridor. If a new transmission expansion improves the constraint in a particular corridor, the respective amount accumulated in the Exceed Fund is used to cover up to 85 % of the expansion costs.	
Ontario, Canada	The Ontario market is based around a single pricing zone. Ontario is interconnected to Manitoba, Quebec, New York, Michigan and Minnesota, through 12 'intertie' zones. IESO is the market and system operator, responsible for five-minute dispatch of: • a real-time energy market; and • three real-time operating reserve markets. Prices for all markets apply across Ontario and are published ex post. There are separate 'procurement markets' for ancillary services such as black start and IESO also runs a transmission rights market for trade with interconnected markets.	The objective of the dispatch algorithm is to minimise the cost of serving demand, based on generators' offers to supply. The dispatch algorithm produces both an unconstrained and a constrained dispatch.	The unconstrained dispatch price is used for the purpose of pricing. A market clearing price for energy and the three classes of operating reserve are determined for Ontario as well as for each of the twelve intertie zones. Generators and loads are paid constrained-on and constrained-off payments if their dispatch is affected by transmission limits (as determined by comparison of the constrained and unconstrained dispatch).	Not applicable