AEMC

Australian Energy Market Commission

Congestion Management Review

Draft Report

27 September 2007

Signed: ....

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

Commissioners
Tamblyn
Carver
Woodward

Inquiries

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

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

Citation

AEMC 2007, *Congestion Management Review*, Draft Report, 27 September 2007, Sydney.

About the AEMC

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

Overview

The publication of this Draft Report by the Australian Energy Market Commission is an important milestone in the Congestion Management Review (CMR). The CMR was initiated by a direction from the Ministerial Council on Energy (MCE) to examine and report on improved arrangements for managing physical and financial trading risks associated with material congestion in the National Electricity Market (NEM) prior to it being addressed by investment or regional boundary change, including the feasibility of a constraint management regime. The recommendations in this Draft Report, in combination with other related initiatives, represent a significant package of reforms that relate, in different ways, to how congestion is managed in the NEM. This package of reforms comprises:

- The Final Rule Determination on the Abolition of the Snowy Region, which the Commission views as an enduring solution to the largest material and persistent congestion issue in the NEM;

- The Draft Rule Determination on the Process for Region Change, also published today, which sets out a new process for identifying and assessing further changes to the NEM pricing Regions, should material and enduring congestion emerge in the future. Appropriate changes to regional boundaries should help reduce the physical and financial trading risks of congestion;

- The reforms to the regulation of transmission services, the Regulatory Test and the Last Resort Planning Power, which establish an incentive framework for more efficient investment in, and operation of, monopoly transmission networks. The development of a new service performance incentive arrangement by the Australian Energy Regulator (AER) is a key part of this new framework. All of these measures should lead to enhanced transmission capability, which should reduce both the incidence and participant trading risks of congestion;

- The Commission's ongoing work on a National Transmission Planner, in the light of the direction provided by the MCE, which can be viewed as a continuation of the work to identify and deliver more efficient transmission investment; and

- The recommendations contained in this Draft Report, being: measures to improve the predictability of pricing and dispatch outcomes, measures to improve existing risk management instruments and measures to support transparent disclosure of transmission capability.

In the Commission's view, these reforms – which have all been made within the framework of the current NEM design – will, over time, help anticipate and address efficiently the most salient instances of congestion in the NEM. For these reasons, this Draft Report refers to, and should be considered in conjunction with, these other reforms.

In this context, the Commission notes that outside of the Snowy region, there is limited evidence of *material* and *persistent* congestion in the NEM. Congestion in the NEM generally appears to be relatively low and stable. Where congestion is material, it appears to have a short "life-cycle". This means that it typically arises in a particular location, remains evident for one or two years and is then addressed by transmission investment or other market responses. Further, the economic costs of congestion appear to be very limited with the exception of the legacy congestion issues in the Snowy Region which have now been addressed by the Commission. These findings were derived from the data and analysis provided by the National Electricity Market Management Company (NEMMCO), the AER, the Commission's consultants and stakeholder submissions, all of which are discussed in detail within the Draft Report. The congestion that does appear to be increasing largely relates to outages, for which the remedies are appropriately pursued through the economic regulation of Transmission Network Service Providers (TNSPs) by the AER under the Rules. For example, most of the congestion evident in New South Wales, Queensland and Tasmania was driven by outages. Therefore, in order to ensure a proportionate response to the magnitude of the problem, the Commission is recommending incremental change within the existing NEM market design rather than fundamental change to the market design.

The three key areas of change recommended in this Draft Report are as follows:

Measures to improve the predictability of pricing and dispatch outcomes

The Commission believes that the predictability of pricing and dispatch outcomes could be improved if the Rules appropriately reflected the MCE's position on the use of fully optimised constraint formulation in dispatch and if NEMMCO was obliged to formulate and apply constraint equations in accordance with published guidelines. Participants could also benefit from the provision of timelier and more detailed information on the nature, duration and impact of network outages and congestion. All of these measures ought to help reducing participants' physical and financial trading risks due to congestion. Policy-makers considering the need for more fundamental reforms in the longer term may also benefit from the provision of such information.

Measures to improve existing risk management instruments

The Commission has recommended changes relating to the availability and potential usefulness of Inter-Regional Settlements Residue (IRSR) units. These instruments are used by participants for hedging the contract basis risk arising from inter-regional price differences. The recommendations involve altering the structure of Settlements Residue Auctions (SRAs) to allow participants to acquire IRSR units up to three years in advance (instead of the present one year in advance) and examining changes to the management of negative settlement residues by NEMMCO. Such changes, if implemented, could improve dispatch efficiency as well as the value of IRSR units as a hedging instrument, which should in turn help participants better manage the financial trading risks of congestion.

Measures to support transparent disclosure of transmission capability

The Commission considers it important in the longer term for both participants and policy-makers to have access to robust measures of transmission capability. These measures could enable participants to better predict the likely impact of congestion of their physical and financial trading risks and provide the basis for the consideration of further reforms, such as more specific TNSP accountabilities for network performance.

Notably, the Commission did not find it appropriate to recommend changes that would increase the degree of locational pricing in the NEM outside the proposed regional boundary change process. This position is based on the historical evidence regarding the short life-cycle of most constraints, the significant complexity and unpredictability Inherent in implementing interim pricing mechanisms and the implications of more locational pricing for the basis risk faced by participants who are party to financial derivative contracts. In general, while more refined locational pricing arrangements reduce generators' physical dispatch risks, they tend to increase basis risk. This is likely to give rise to the need for more complex risk management instruments to enable market participants to hedge the increased basis risk, with associated design and implementation challenges. For example, the means of allocating new financial transmission rights is likely to be extremely contentious. The evidence on the materiality of congestion in the NEM does not support the introduction of such a pricing intervention at this time.

The Commission believes that the recommendations made in this Draft Report, combined with the major reforms implemented or underway through related processes, represent a substantial package of reforms for improving the management of congestion in the NEM. The reforms already implemented and underway represent significant changes to the NEM within the existing market design, which the Commission expects will substantially improve the environment for managing network congestion. The additional CMR recommendations have been developed in this context and in light of the evidence of the limited materiality of congestion in the NEM to date. Therefore, the Commission believes that the package of changes, taken as a whole, represents a proportionate response to the present incidence and materiality of congestion. However, if notwithstanding these changes, material and persistent congestion were to arise in the future, the Commission considers that there may be circumstances where consideration might be given to the merits of greater locational pricing of generation. In these circumstances, policy-makers would need to resolve the various issues surrounding the implementation of interim pricing mechanisms and the development and allocation of basis risk management instruments that the Commission has identified in this Draft Report and in its previous publications.

The Commission welcomes feedback from stakeholders on the analysis and recommendations contained within this Draft Report.

This page has been intentionally left blank

Contents

Abbreviations

AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ANTS	Annual National Transmission Statement
Capex	Capital Expenditure
CBR	Constraint-Based Residues
CMR	Congestion Management Review
Code	National Gas Code
Commission	see AEMC
CPI	Consumer Price Index
CSC / CSP	Constraint Support Contract / Constraint Support Payment
FTR	Financial Transmission Rights
IRSR	Inter-Regional Settlements Residue
LRPP	Last Resort Planning Power
MAR	Maximum Allowed Revenue
MCE	Ministerial Council on Energy
MW	Mega Watts
NCAS	Network Control Ancillary Services
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEMMCO	National Electricity Market Management Company
NOS	Network Outage Schedule
NSA	Network Support Agreement
NSCS	Network Support and Control Services
PFC	Positive Flow Clamping
POS	Planned Outage Schedule
RRN	Regional Reference Node
RRP	Regional Reference Price
Rules	National Electricity Rules
SOO	Statement of Opportunities
SRA	Settlements Residue Auction

TNSP	Transmission Network Service Provider
TUoS	Transmission User of Service

This page has been intentionally left blank

Summary

Executive Summary

In October 2005, the Ministerial Council on Energy (MCE) made a notice of reference under the National Electricity Law (NEL) directing the Australian Energy Market Commission (AEMC or Commission) to consider the requirement for and scope of enhanced trading arrangements in relation to congestion management and pricing in the National Electricity Market 9NEM). This review is hereinafter referred to as the Congestion Management Review (CMR or the Review) and this Draft Report presents the AEMC's proposed recommendations to the MCE on enhanced congestion management arrangements.

The Commission's view is that the present level and impact of congestion on participants' trading risks in the NEM is insufficient to warrant fundamental changes to the design of the market. This is particularly the case in light of the significant reforms recently made by the Commission to the regulatory framework for transmission businesses, the resolution of the specific issues relating to congestion in the Snowy region and the current proposals of the MCE on national transmission planning. However, a number of worthwhile incremental changes could be made that would improve information about congestion and improve the firmness of existing risk management instruments.

Terms of Reference

The Terms of Reference (ToR) for the CMR requires the Commission to examine and report on:

- Improved arrangements for managing financial and physical trading risks associated with material network congestion, with the objective of maximising net economic benefit to all those who produce, consume and transport electricity (clause 3.1); and

- The feasibility of a constraint management regime as a mechanism for managing material congestion until those issues are addressed through investment or a boundary change (clause 3.2).

In undertaking these tasks, the ToR requires the Commission to:

- Take account of and articulate the relationship between a constraint management regime, constraint formulation, regional boundary change criteria and review triggers, Annual National Transmission Statement (ANTS) flowpaths, the Last Resort Planning Power (LRPP), the Regulatory Test, and Transmission Network Service Provider (TNSP) incentive arrangements (clause 3.2); as well as

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

The Commission has interpreted the ToR as requiring:

- An assessment of the *materiality* of the costs of congestion in parallel with the consideration of various options for changes;
- That only net beneficial options should be proposed – the ToR recognise that it would not be efficient to eliminate all transmission congestion;
- Consideration of options that would apply to material congestion issues for limited periods until investment or boundary change addresses the constraint – this necessarily circumscribes the range of options to be considered; and
- Consideration of options that enable participants to better *manage* the trading risks of congestion directly, as well as options that could reduce the *prevailing level* of congestion and thereby reducing the risks of congestion indirectly.

Process and criteria for the CMR

The Commission has approached this Review in an open and consultative manner. It has sought comments from stakeholders on the range of options for improving risk management for consideration and also on the extent and materiality of congestion.

Prior to this Draft Report, the Commission had already published an Issues Paper in March 2006, a Statement of Approach in June 2006 (revised in December 2006) and a Directions Paper in March 2007.

In addition, the Commission has progressed a number of Rule changes that directly relate to the management of congestion in the NEM, including those dealing with congestion in the Snowy area of the NEM, regional boundary change criteria and the Last Resort Planning Power. The Commission sought to deal with all of these related matters in an integrated manner due to the interdependencies between them.

The Commission applied the NEM objective in undertaking the Review. The NEM objective comprises both efficiency-related components as well as less technical components such as the predictability and stability of the regulatory arrangements.

Context

Meaning of congestion

Congestion refers to a "bottleneck" on the transmission network, which arises when the ability of the network to accommodate the power flows emerging from the process of "dispatching" generation to meet demand (or "load") has been reached. The power flows resulting from the dispatch process are dependent on the interaction of the demand for and supply of electricity across different locations in the NEM. The ability of the network to handle power flows is referred to as its "capability". Capability is a dynamic variable that depends on both the technical design limitations of individual network elements – known as their "capacity" – as well as the way in which those network elements are operated collectively under different power system conditions at each point in time. Hence, congestion is specific to a pattern of electrical flows and the capability of the transmission system, and specific to a point in time. Congestion might emerge at a location in one five-minute dispatch interval, but disappear in the next interval.

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

Rules for managing congestion

There are three broad categories of Rules relating to congestion management:

- Dispatch Rules, including the way the physical power system is represented in the NEM dispatch engine (NEMDE), through constraint equations;

- Pricing and Settlement Rules, including the way prices are determined and settlement is carried out for each market participant; and

- TNSP and NEMMCO activities, including short-term arrangements for transmission availability and transfer capability and long-term arrangements for network and non-network investment.

<u>Dispatch Rules</u>

NEMMCO's role as market and system operator includes managing the dispatch process for each 5-minute dispatch interval. NEMDE calculates the least-cost way of dispatching generation to meet load, based on the prices and quantities contained in the bids and offers submitted by market participants, while remaining within network security and reliability parameters contained within constraint equations.

Each network constraint equation is a mathematical representation of the way in which different variables affect flows across particular transmission limits. Network constraints thus imposed a limitation on dispatch related to the physical capability of the transmission network. There is a separate constraint equation for each limitation imposed on the dispatch, including those relating to the management of system security due to the occurrence of network outages.

The current convention for network constraints used in NEMDE is to include terms that can be controlled by NEMMCO through dispatch on the left hand side (LHS) of the equation, and terms that cannot be controlled by NEMMCO through the dispatch on the right hand side (RHS) of the equation. The sum of the terms on LHS cannot be greater than the sum of the terms on the RHS. This is the so-called "fully co-optimised" form of constraint formulation. The extent to which a particular term on the LHS uses up the limited capacity of the constraint is reflected in its coefficient in the constraint equation. Congestion occurs when a constraint "binds", meaning that it has a direct and limiting impact on the dispatch (which can often be extremely far-reaching). Importantly, inherent within NEMDE is the notion that the marginal economic value arising from an incremental increase in network capability is the same as that arising from the same incremental reduction in generation (or load) that is contributing to the congestion. This means that the two alternative ways of relieving congestion are for NEMMCO to change the level of variables under its control, or raise the RHS limit of the constraint. This latter option is outside the control of the dispatch engine and requires external action by NEMMCO or a TNSP.

Pricing and settlement

The dispatch process takes account of not only the price at which participants make bids and offers, but also the location (or "node") at which participants are situated within the transmission network. By contrast, the pricing and financial settlement of participants is implemented on a regional basis in the NEM, where each region broadly corresponds to each State in the NEM. A settlement price is calculated separately for each region for each thirty minute trading interval. This is known as the regional reference price (RRP). The RRP is the cost (based on bids and offers) of supplying an additional unit of electricity at a particular node in the region known as the Regional Reference Node (RRN). The RRNs are generally located in the major load centres in each region, such as at or near the capital city. All generators in a region receive the applicable RRP on the volume of energy for which they are dispatched, regardless of whether or not they are located at the RRN. Similarly, all loads in a region pay the applicable RRP for the amount of electricity they consume.

When congestion occurs, it can cause differences in the marginal cost of supplying energy at different locations. To the extent this leads to different marginal costs of supply at different RRNs, the result would be a divergence of RRPs. These inter-regional price differences play an important signalling role in the NEM. In the short term, they provide signals to generators in high-priced regions to produce more and for loads to consume less, relative to generators and loads located in low-priced regions. Over time, price differences can encourage efficient decisions by market participants concerning when and where to invest in generation and load assets. Inter-regional price differences also create financial trading risks for participants.

However, congestion can also cause differences in the marginal cost of supply within a region, between the RRN and other nodes in the region. The marginal cost of supply at each node other than the RRN is referred to as the local or "pseudo" nodal price, and this is calculated as a by-product of the dispatch process. To the extent that congestion causes divergences between the RRP and local nodal prices in the NEM, this impact is not reflected in differences in the prices paid or received by participants located at those other nodes in the region. This disjoint between the implied nodal prices yielded by the dispatch process and the RRPs used for settlement is commonly referred to as "mis-pricing". Mis-pricing can create trading risks for participants and promote behaviours that reduce economic efficiency

TNSP and NEMMCO influences on congestion

Both the TNSPs and NEMMCO can influence the capability of the transmission network and consequently the level and impact of congestion. The behaviour of TNSPs in operational and investment timescales can impact on the capacity and the transfer capability of the transmission network at any point in time. The Commission has recently made Rules to provide stronger financial incentives for TNSPs to implement operational actions that relieve congestion in the short-term and extract the maximum efficient level of transfer capability out of the existing network capacity and to invest efficiently in the longer term. Importantly, the activities of NEMMCO can also influence network capability through, for example, determining the safety margins use in ensuring retention of system security.

Costs imposed by congestion

Congestion and the way it is managed in the NEM imposes a number of risks and costs on producers, consumers and transporters of electricity in the market.

Direct costs of congestion

As congestion refers to the inability of the transmission network to accommodate the power flows emerging from the dispatch process, the most direct impact of congestion is to require the dispatch of higher cost plant to meet demand than would otherwise be the case. This imposes a welfare loss on the market as a whole.

Indirect costs of congestion

Congestion also imposes costs through its effect on participant trading risks. These trading risks largely derive from participants' entry into financial derivative contracts, which are used to hedge exposures to volatile wholesale spot prices.

As noted above, when constraints bind, either or both of the following may occur:

- Differences in RRPs caused by differences in the marginal cost of supply at different RRNs; and

- Mis-pricing of generation and load within a region caused by differences between the RRP and the implied local nodal prices.

The first of these impacts gives rise to financial trading or "basis" risk for participants, to they extent they have entered financial contracts that are settled against the RRPs of other regions. Such participants are vulnerable to differences between their local RRP and the RRP at which those contracts are settled.

Participants can acquire, through regular auctions, Inter-Regional Settlement Residue (IRSR) units to partially hedge the basis risk of contracts referenced to a different region's RRP. When RRPs diverge, inter-regional flows create IRSR funds, which are equal to the difference between the RRPs of the destination (i.e. importing) and source (i.e. exporting) regions, multiplied by the volume of flow and time duration. However, IRSR units do not typically provide a firm (i.e. reliable) hedge against inter-regional price differentials. To this extent, the actual or potential presence of congestion may deter participants contracting across regional boundaries. Ultimately, this could lead to higher contract premiums and higher retail prices. This, in turn, could lead to lower electricity consumption than would otherwise be the case, harming allocative efficiency. Reduced contract competitiveness could also reduce dynamic efficiency in the longer term by distorting generation and load investment incentives in terms of the timing and location of new plant.

On the other hand, mis-pricing gives rise to physical or "dispatch" risk for generators, because it means that generators may be either:

- ***Constrained-on*** — when a generator is dispatched for a quantity that is greater than the amount it is willing to produce at the (settlement) price it is paid; or

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

The main risk for a constrained-on generator is that it incurs a loss on the additional output it is required to produce. The main risk for a constrained-off generator is that it is prevented from earning the RRP on the volume of output it would wish to generate at that price. To the extent such a generator is financially contracted, it may be required to make cash difference payments on its contracts that are not funded by the generator's revenues in the spot market. When a generator is constrained-on, it is said to be "negatively mis-priced", because its settlement price (the RRP) is less than the nodal price used to determine its dispatch volume. Conversely, a constrained-off generator is said to be "positively mis-priced" because its settlement price (the RRP) is greater than the nodal price used to determine its dispatch volume.

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

- Constrained-on generators being incentivised to make offers up to the maximum price of $10,000/MWh to avoid being dispatched; or

- Constrained-off generators being incentivised to make offers down to the market floor price of -$1,000/MWh to seek to be dispatched.

Typically, such offer prices would not reflect generators' underlying resource costs of production. In an environment of such "disorderly bidding", the dispatch process may not yield least-cost outcomes. Further, to the extent that generators cannot manage their dispatch risks by bidding in a disorderly manner, they may be inclined to reduce their level of financial contracting and/or increase contract premiums. In either case, there will be negative implications for allocative and dynamic efficiency. In some cases, generators may be subject to *both* basis risk and dispatch risk.

A key point to note is that there may be a trade-off between basis risk and dispatch risk. This is because more "granular" spot market pricing arrangements – in which more RRPs are calculated at different locations – may reduce mis-pricing and hence reduce dispatch risk, but may simultaneously increase the basis risk that participants need to manage. This, in turn, could increase the complexity and unpredictability of the market arrangements.

Materiality of congestion in the NEM

An understanding and assessment of the materiality of congestion is required to determine what, if any, changes should be made to the current market arrangements. The Commission has considered both the data on the prevalence, duration and location of congestion as well as on the indicators of the economic costs of congestion in the short and long term. The Commission also took account of the views of participants expressed in submissions and meetings.

In short, the evidence supports the Commission's recommendation that there is no strong justification for introducing localised congestion pricing mechanisms as part of this Review. The costs of developing and implementing these mechanisms are likely to outweigh the benefits of reduced mis-pricing. Further, a key point of material congestion in the NEM – the constraints between Murray and Tumut – has been recognised through a boundary change decision.

Prevalence, duration and location of congestion and mis-pricing

The Commission considered data on the level and duration of congestion from the annual Australian Energy Regulator (AER) reports on the indicators of the market impact of transmission congestion, the NEMMCO's Statement of Opportunities – Annual National Transmission Statement (SOO-ANTS) and work provided by Dr. Biggar and NEMMCO on the patterns of mis-pricing in the NEM. This evidence is discussed extensively in Appendix D. No clear consensus emerged from the submissions about whether congestion is a material problem in the NEM. Some parties stated that the evidence did not suggest that system normal constraints were having a significant adverse effect on dispatch efficiency. Other parties considered that congestion was a material problem and would continue to increase.

This data shows that the nature of congestion in the NEM can be quite unpredictable, with both the location of the significant constraints and the total duration of each constraint binding changing significantly on an annually basis. Most constraints appear to have a relatively short "life–cycle", in that they may cause some mis-pricing for one or two years before being largely addressed by investment in transmission or generation infrastructure. There are only a few instances where congestion at a location has remained persistent – the consensus of opinion at the Industry Leaders Strategy Forum was that, except for the Snowy region, congestion did not appear to be a major problem in the NEM at the present time.

Some key findings of the various analysis undertaken were:

- Dr. Biggar found that the NEM-wide incidence of mis-pricing had been increasing since 2003/04. He considered that mis-pricing was a frequent and enduring issue at a relatively large number of connection points, stating that around 95 connection points in the NEM have been mis-priced for more than 100 hours per annum on average over the last 3 years;

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

- Generators were significantly more likely to be positively mis-priced (constrained-off) than negatively mis-priced (constrained-on). In 2005/06 the ratio between the two forms of mis-pricing was 3 to 1. It is negative mis-pricing for which the Commission has the greatest concerns, because it means generators are being forced to produce more than they would want at the RRP;

- The average mis-priced amounts per mis-priced dispatch intervals was very high, ranging around \$500 to \$1000/MWh for those generators who were subject to positively mis-pricing and between -$300 and -$6000/MWh for those generators who were negatively mis-priced. These results suggest there is a high probability of disorderly bidding occurring when a constraint binds;

- Only a small number of connection points in the NEM were mis-priced by more than $5/MWh for all three years of the study. These connection points all related to small gas or hydro plants in Queensland; and

- The average hours of mis-pricing due to system normal events were fairly constant at around 50 hours per year over the three years. However, there was an increasing trend in the duration of mis-pricing due to transmission outages, from 20 hours in 2003/04 to over 120 hours in 2005/06. This was mainly caused by the increased incidence of outage-caused congestion in both the Snowy and Queensland regions. The Queensland increase was due to a number of lightning events affecting flows between Central and South Queensland and an outage at the Gladstone transformer.

The Commission also assessed the outlook for the future trend in congestion, taking account of factors such as the completion of NEMMCO's program of constraint reformulation and the extensive transmission investment program of TNSPs. Against this background, the Commission considers that the incidence of congestion is unlikely to escalate in the near future and there does not appear to be any location in the NEM where material congestion is likely to persist.

Economic costs of congestion

The occurrence of congestion alone does not imply that it represents a material economic problem. This requires quantifying the economic costs of congestion and then coming to a view as to whether those costs are sufficient to warrant changing the Rules. This assessment will vary depending on the nature of the change being contemplated, with more costly changes requiring a higher materiality hurdle.

Hence, the Commission considered evidence on the impact of congestion on:

- Productive (or dispatch) efficiency;

- Risk management and forward contracting; and

- Dynamic efficiency.

Productive efficiency

<u>AER indicators</u>

The AER has published a series of historical indicators of the annual dispatch costs of congestion for the financial years 2003/04 to 2005/06. These indicators are:

- The total cost of constraints (TCC);

- The outage constraint cost (OCC); and

- The marginal cost of constraints (MCC) (See Table S.1 below).

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

Table S.1: AER indicators of the market impact of transmission congestion

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

Note: The 2005/06 Figures include any congestion within the Tasmanian transmission network for the first time. Data source: AER Indicators of the market impact of transmission congestion, Report for 2003/04, 9 June 2006; Report for 2004/05, 10 October 2006, and Report for 2005/06, February 2007.

Converting the AER's measures into indices with a base year of 2003/04 reveals a near doubling of the TCC and a tripling of the OCC in the three years to 2005/06.

As noted in the Directions Paper, the AER indicators ought to be interpreted with care, as there are important limitations inherent in the assumptions and methodology. Accepting these limitations, the Commission notes that the AER estimates are of a very small magnitude compared to the annual wholesale sales of $6 - $11m in the NEM. Importantly, the more recent AER reports have indicated that an increasingly significant proportion of the TCCs are related to transmission outages and the majority of the costs occurred on a few days per year.

<u>Frontier Economics mis-pricing costs analysis</u>

Frontier's analysis attempted to calculate the dispatch inefficiency costs caused by generators bidding in a disorderly manner to avoid being either constrained-on or –off in a market experiencing mis-pricing. This analysis did not allow for any material market power, meaning that generators that were not mis-priced were assumed to bid their capacity into the market at their short run marginal cost. Meanwhile, generators that were constrained-on were assumed to bid their capacity at $10,000/MWh to avoid being dispatched and generators that were constrained-off were assumed to bid their capacity at -$1,000/MWh in order to be dispatched.

Frontier found production costs in the scenario with mis-pricing across the entire NEM to be $8.01 million higher than in the base case in which all plant were assumed to bid their capacity at short run marginal cost. This is 0.47% of annual total production costs across the NEM of more than $1.7 billion. The Commission considers that this analysis indicates that the impact of constraints binding and causing inefficiency through mis-pricing is relatively low.

Economic modelling of congestion in the Snowy region

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

Risk management and contracting

As noted above, congestion can contribute to participants' trading risks. The materiality of the financial risks arising from constraints is dependent on the effectiveness of the existing risk management instruments available to participants.

Through submissions, participants acknowledged the lack of firmness offered by the existing SRA products, but were concern about the risks of introducing major changes, especially if they were made in isolation to initiatives to improving transmission performance. The Commission also found that participants' appetite for inter-regional trading varied greatly and that participants used a portfolio of instruments to manage risk rather than just relying on one mechanism.

Dynamic efficiency

The Commission considered several approaches for estimating the dynamic efficiency implications of congestion. The Commission placed a very high priority on the dynamic efficiency implications, especially in light of significant planned energy investment planned over the next 5 to 15 years.

In its 2006 ANTS, NEMMCO estimated the present value of the total market benefits of removing all network constraints at $2.2 billion over the next ten years, with benefits arising due to lower dispatch costs, deferral of capital expenditure and reliability savings. However, the Commission remains of the view expressed in the Directions Paper that this analysis has limited usefulness for the CMR.

In the Directions Paper, the Commission also discussed a report prepared by Intelligent Energy Systems (IES) for the LATIN Group on the potential future dynamic efficiency impacts of more granular congestion and transmission pricing arrangements in Queensland. The IES report found that both options would lead to a more efficient pattern of generation and transmission investment in Queensland, with the scenario combining both options yielding greater efficiencies than the scenario relying solely on more granular congestion pricing.

The IES report represents an important and useful attempt at quantifying such effects under various pricing regimes. However, the Commission considers that the IES modelling exhibits a number of serious limitations. These include no consideration of the risk implications and implementation costs of introducing nodal pricing, no verification of whether the location of the additional generation was plausible and simplistic modelling of generator and transmission investments. The Commission also agrees strongly with Stanwell and Powerlink that there are more important influences on generation location than price signals. These influences include portfolio risk, carbon risk, fuel source, water source and environmental restrictions.

Full details of the Commission's analysis are contained in Appendix F. For these reasons, the Commission does not consider that the cost estimates of the current regional pricing regime contained in IES report are realistic.

Nevertheless, the Commission does recognise that that in the future, work will be required to develop a more robust framework for modelling dynamic efficiency impacts, especially for regional boundary assessments.

Pricing

The manner in which congestion is priced in the wholesale market has an important role to play in managing congestion. Congestion that is reflected in price divergences should overcome mis-pricing, reducing dispatch risk and sending economic signals for the location and timing of future investment. At the same time, more granular wholesale market pricing creates basis risk that participants need to manage. The net effect of any options implementing more refined pricing in the wholesale market depends in part on what financial instruments are available for managing this basis risk, and how market participants obtain those instruments.

The Directions Paper outlined a number of pricing options for managing congestion:

- Pricing for constrained-on generation;
- Limited forms of nodal pricing;
- Constraint Support Contracts and Constraint Support Pricing (CSC/CSP); and
- Constraint-Based Residues (CBR).

The Commission notes that all of these options, and the many variants and hybrids that exist, represent different ways of addressing the same core issues. The Commission therefore sought to identify a common analytical framework and terminology for explaining and comparing the different options.

Analytical framework

<u>Constraint prices</u>

The cost of a constraint can be measured by calculating the reduction in the total cost of the dispatch (based on participants' bids and offers) that would result if the binding constraint could be marginally relaxed. Constraint prices can be used to calculate the extent to which a particular point on the network is mis-priced relative to its RRN. If there are no binding constraints, there will no mis-pricing.

<u>Constraint rents</u>

When a constraint binds, the value of transmission capability is equal to the volume of energy (in MWs) being constrained multiplied by the constraint price. This value can also be referred to as the "rent" earned by the constraint when it binds. How these rents are distributed, either implicitly through the dispatch process or explicitly through the sale or allocation of financial instruments, is a key differentiating features of congestion pricing regimes.

<u>Types of financial instruments derived from congestion rents</u>

Congestion rents provide the building block of any set of arrangements for reflecting network congestion in prices in the wholesale market. The basic approach is to design a financial instrument to enable parties to buy a share in the congestion rents when they occur and thereby hedge the risk. There are two main approaches to defining such instruments:

- An *unbundled right* to a share of congestion rents for each individual constraint equation involved in the congestion pricing scheme; and

- A *bundled right* to a share of congestion rents across the 'bundle' of constraint equations involved in the congestion pricing scheme.

The key distinguishing feature between the options outlined in the Directions Paper is the manner in which rights to congestion rentals are "bundled". For example, the CSC/CSP option (either as a single instrument or rolled out comprehensively across the NEM as proposed by the LATIN Group) represents a form of bundled rights. Under a CSC/CSP option, a set of generators (and interconnectors) and a set of constraints is identified. Each generator involved in the scheme is allocated a financial instrument (a CSC) that entitles it to have a specified volume of electricity settled at the relevant RRP. Any output over and above the amount specified in the CSC is settled at a price consistent with the congestion prices implied by the constraints involved in the scheme (in effect, the generator's local nodal price). An Financial Transmission Right is also a form of *bundled right*, involving the bundle of constraints affecting prices between two nodes. An SRA unit is another example of a bundled right, as is the existing regional settlement process in the NEM.

On the other hand, the CBR approach, proposed by Dr. Darryl Biggar, represents a form of unbundled rights. For each constraint equation, the rent is identified and placed in its own separate fund. Rights to shares in these funds would then be either allocated or auctioned. Participants would have an opportunity to trade these rights in such a way as to construct the financial hedges there require. The most general form of CBR is not limited to generators; it would include load.

<u>Methods of distributing congestion rents</u>

There are three main approaches to distributing rights to congestion rents:

- *Auction* the rights;

- *Negotiate* a distribution of rights, and *arbitrate* if no agreement can be reached, or

- *Allocate* the rights in accordance with an administrative rule set when the localised pricing intervention is established.

Each of these methods raises difficult issues. In a regional market such as the NEM, rights to congestion rents are allocated implicitly through the dispatch process.

Assessment framework

The Commission assessed the options against an assessment framework based on the following factors:

- Influence on bidding behaviour and dispatch efficiency;
- Impacts on hedging;
- Practicability and complexity of localised, time-limited application;
- Rights allocation and competition issues;
- Predictability and regulatory risk; and
- Proportionality of response.

Bidding behaviour and dispatch efficiency

As noted above, all of the pricing options put forward would involve a degree of localised wholesale spot market pricing. In a market characterised by price-taking bidding behaviour, ensuring that settlement prices are consistent with the prices used in the dispatch process ought to deter disorderly bidding and promote efficient dispatch based on participants' underlying resource costs. However, where generators have some degree of market power, correcting mis-pricing does not necessarily improve the economic efficiency of dispatch. In such an environment, as was the case in the Snowy boundary situation, the extent to which outcomes are likely to be efficient is an empirical matter. This is because generators with some influence over their local nodal price may seek to either withhold a proportion of their output or offer it at a very high (non-cost-reflective) price in order to maximise their profits based on a price-volume trade-off.

Impacts on hedging

The introduction of localised congestion pricing also affects the ability of market participants to hedge price risk effectively. The introduction of more settlement prices for generators has two effects. First, it reduces the extent to which constraints involving both local generators and interconnector flow terms dilute the firmness of the IRSR units when they bind. Second, it reveals the need for additional hedging instruments for managing trading risks within and across regions. Combining the introduction of localised congestion pricing with the introduction of additional financial instruments for hedging congestion price risk offers a theoretical means of increasing the volume of firm hedges available in the market. Whether this is practical is discussed below.

Practicability and complexity of implementation

A number of issues need to be resolved with the implementation of a time- and location-limited congestion pricing regime. These are:

- The threshold criteria and process for *introducing* a congestion pricing regime;
- The identity of the constraints to be "priced" as part of the regime; and
- The threshold criteria and process for *removing* a congestion pricing regime, given that it is intended to be a temporary measure only.

While the trial of a CSC/CSP instrument at Tumut (the Snowy Trial) tackled some of these issues, the Commission does not believe that the approach adopted for the Snowy Trial is more widely applicable. This is because only one generator was directly involved and the underlying congestion problem was clearly identifiable, well understood, and not liable to change in the short to medium term.

As noted above, apart from the Snowy area, congestion in system normal conditions has generally been relatively low-level and transitory. This raises the question of how the need for intervention ought to be identified sufficiently far in advance to allow managed and orderly design and implementation, if historic measures of congestion are not reliable indicators of future congestion. While locations can be identified easily with the benefit of hindsight, it is not at all clear to the Commission that they can be forecast accurately. Notably, under the Commission's proposed new process for region change, a stage will be reached where the Commission has considered and accepted a proposed region change, with an associated default implementation lead time of 3 years. However, while in these circumstances the congestion problem is clearly identified, it is questionable whether an interim pricing intervention is appropriate. The purpose of the proposed 3-year lead time is to provide market participants with adequate time to adjust to the region change. Therefore, implementation of a congestion pricing scheme *in advance of region change* may not be consistent with the policy intent behind the 3 year lead time proposal, given that in some ways a congestion pricing scheme such as a CSC/CSP simulates some of the features of region change.

If congestion pricing interventions were adopted in other circumstances, the evidence on the apparently transitory nature of congestion and the lack of robust leading indicators suggests two possible risks. First, that instances where greater congestion pricing might improve the efficiency of outcomes are missed. Second, that congestion pricing schemes are introduced where they deliver no benefit.

<u>Allocation of congestion rights</u>

The Commission considers that the allocation of explicit congestion rights is not a matter that is easily resolved. As noted above, the LATIN Group suggested that CSCs could be allocated to existing generators on the basis of a representative dispatch scenario. This would have the advantage of ensuring that new investment in generation was based on future expected spot prices at the relevant location, rather than the proponent's expectation of being able to obtain the RRP by bidding in a disorderly manner. However, the Commission is concerned that allocating congestion rights to incumbents in this way could have two detrimental impacts.

First, the allocation of rights based on historical dispatch would create its own implementation challenges. For example, the choice of the historical period according to which the allocation referred (the "base" period) would be controversial. Second, it would imply a right of incumbents to settlement at the RRP that has never been formally recognised as part of the NEM arrangements. An allocation method that provided existing generators with (potentially tradable) rights in preference to prospective new entrants could be potentially viewed as discriminatory and anti-competitive. Furthermore, it could involve significant wealth transfers and represent material changes to the way in which the market operates over time. Consistent with good regulatory practice, such intervention should not be undertaken lightly. Finally, depending on how the rights were specified, it could create barriers to entry.

Alternatively, congestion rights may be allocated via auctioning. While this would avoid many of the issues arising from allocation to incumbents, it would raise other implementation issues. For example, participants are likely to want relatively long-term rights to enable them to hedge long term financial contracts. Yet the nature of congestion rights is likely to change over time as constraint equations are altered to reflect changes to network capability, generation investment and load growth. Purchasers of congestion rights would be faced with uncertainty over the value of their rights in these circumstances.

<u>Predictability and regulatory risk</u>

The Commission believes that each step of the implementation of congestion rights would be contentious and time-consuming. Further, even if implementation of a congestion pricing regime were uncontentious amongst participants, the risk would remain that a regime could be implemented in circumstances where there proves to be no material congestion problem to address. While it could be contended that this risk is relatively small because the additional price risk will be minimal if there is no congestion, the possibility of inappropriate regulatory interventions in the pricing and settlement arrangements creates an additional form of regulatory risk.

Given that substantial new investment is likely to be committed in the NEM over the next few years, the Commission considers the need for predictability in the market pricing and congestion management arrangements to be of paramount importance.

<u>Proportionality of response</u>

The Commission considers that in light of:

- The evidence of limited material and persistent congestion in the NEM;
- The difficulty of predicting when and for how long congestion will occur;
- The temporary nature of any congestion management regime and the numerous implementation and allocation problems surrounding the provision of congestion rights for parties to hedge the resulting basis risk;
- The scope for investment or regional boundary change to address material and enduring congestion in the longer term; and
- The ambiguity over whether locational pricing will improve the economic efficiency of dispatch where parties have some degree of market power,

the endorsement of a pricing approach to improve congestion management would be a disproportionate response to the problem under examination.

Pricing for constrained-on generation

The Directions Paper raised the question whether constrained-on generators ought to receive some form of compensation reflecting the difference between the price at which they would be willing to supply and the RRP they receive. Such compensation is generally precluded under the current Rules, unless a generator is constrained-on through a formal direction from NEMMCO, or has negotiated compensation with a TNSP. Given the existence of this framework in the Rules, the Commission does not believe it is fundamentally "unfair" that constrained-on payments are not more widely applicable to generators. The case for changing the regime for constrained-on payments must therefore be assessed on the basis of its economic impacts in the context of the NEM objective.

Options for constrained-on payments

One option for implementing constrained-on payments is through a congestion pricing scheme, such as a CSC/CSP. This would be equivalent to a pay-as-bid settlement approach for the volume of output being constrained-on.

There are two main issues with this type of arrangement. First, it would potentially create very acute pockets of temporal market power because generators' bids would affect the price they received. Second, it would require an external source of funding, given that generators who were constrained-off would not have to make payments to ensure that they also faced a locational price.

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

While constrained-on payments would address one type of mis-pricing in the NEM, they raise several concerns. First, they may create the scope for the exercise of transitory market power by constrained-on generators, especially where a generator owns a portfolio of plant around a transmission loop. Another issue is that imposing constrained-on payments regime through the pricing and settlement arrangements might be viewed as pre-empting a transmission response under Chapter 5 of the Rules. As noted above, another issue is the need for external funding.

Finally, on the key issue of materiality, the Commission notes that historically there has been a relatively lower incidence of constrained-on generation than constrained-off generation. This evidence, in combination with the absence of stakeholder submissions highlighting constrained-on risk as a significant issue, does not in the Commission's view provide strong support for change. This view is supported further by the lack of evidence to demonstrate that existing mechanisms for contractual arrangements between generators and TNSPs are not working effectively. Conversely, the Commission is aware of some examples where contractual arrangements are being used in the context of network support.

Risk management

IRSR units are one of the key tools for assisting participants to manage basis risk in the NEM. IRSR units are a form of FTR, and are auctioned in advance through quarterly auctions. The IRSR units associated with a particular "directional interconnector" provide the holder with a share of the positive stream of "residues", equal to the price difference between the two regions joined by the interconnector (in the direction of the directional interconnector) multiplied by the flow on the interconnector (when the flow is in the direction of the directional interconnector). Each IRSR unit relates to a notional 1MW of the nominal flow limit of the corresponding directional interconnector.

IRSR units would provide a reliable hedge against inter-regional price differences if a party wishing to trade between two regions could predict with certainty the level and direction of flow on the directional interconnector when there was a price difference between the regions. However, in practice, this is often not possible due to network outages and the fact that interconnector flow is often dependent on the outputs of various generators throughout in the network. The possibility of negative settlement residues creates an additional source of reduced firmness of IRSRs, but the magnitude of this effect is limited by NEMMCO's current practice of "clamping" interconnector flows if there is the prospect of negative residues accumulating to a value greater than $6,000. Many participants criticised the existing IRSR instrument for lacking firmness. Lack of IRSR firmness could reduce parties' willingness to trade inter-regionally and thereby reduce the liquidity of contract markets.

Against this background, the Commission considered three broad approaches to "firming-up" IRSR units:

- Improving the reliability and predictability of the underlying network;
- Amending the arrangements for managing and funding negative settlement residues; and/or
- Using a source of external funds to increase payments to IRSR unit holders.

On the reliability of the underlying network, the Commission considers that many improvements have recently been, or are in the process of being, implemented. These include the review of transmission regulation (including the Service Target Performance Scheme), the Last Resort Planning Power (LRPP), the MCE Region Boundary Change Criteria and Process and the formation of a National Transmission Planner. The Commission believes that the current reforms must be allowed to take effect before further reforms to improve the reliability and predictability of interconnector transfer limits are contemplated.

On the arrangements for managing negative settlement residues, the Commission suggests that an alternative to recovering negative settlement residues from SRA proceeds may be for NEMMCO to charge the importing region's TNSP directly for any negative settlement residues. This could improve the certainty and clarity of the recovery process. The Commission also proposes to increase the clamping threshold to $100,000, in order to avoid excessive intervention in dispatch. However, NEMMCO should also be obliged to outline in constraint guidelines how it interprets and applies those provisions of the Rules that enable it to effect clamping.

The Commission also raises the option of "positive flow clamping" (PFC) to improve the firmness of IRSRs in cases where binding constraints create incentives for generators to bid in a disorderly manner. PFC works by clamping the relevant interconnector to a positive flow (in the direction of the lower priced region to the higher priced region), rather than clamping to zero flow as is the current practice. This should also create incentives for more efficient generator locational decisions. The Commission does not believe that PFC would create issues for the management of system security. While PFC should increase the willingness of generators to enter contracts with counterparties in other regions, it may, by increasing dispatch risk, reduce the willingness of generators to enter contracts within their own regions. On balance, while it is difficult to say if the volume of contracts offered at a given RRN would increase, the number of potential counterparties should increase. The Commission seeks stakeholders on the merits of this option.

On the scope for firming up IRSRs through an external source of funds, the Commission believes that using external funds to achieve 100% IRSR firmness would be unjustifiably expensive for customers. However, one option may be to allow individual generators or groups of generators to fund negative settlement residues themselves in exchange for clamping to not be applied. An example where this option could be employed would be in Southern Queensland, where when the Tarong constraint presently binds, counter-price flows on the interconnector into NSW causes NEMMCO to implement clamping. This has the result of constraining-off these generators, even where they may be the least-cost plant to serve load in NSW. The Commission notes that there are substantial implementation issues to resolve in developing such an option and would welcome views from stakeholders on the viability and practicality of such Rule change proposals.

SRA design

The Commission has also considered incremental improvements to SRAs that could improve their flexibility and hence their usefulness. Options considered have included longer- and shorter-dated IRSR units, peak and off-peak IRSR units and the sale of some units further in advance.

Of these options, the Commission considers that only the option to sell units further in advance has merit. The benefits of the other options could be obtained by repackaging the existing SRA product, which can be done by market participants themselves or by financial intermediaries.

Information and constraint formulation

Constraint formulation

As noted above, the way in which a constraint equation is formulated can vary. NEMMCO has adopted the use of a "fully co-optimised" constraint formulation, meaning that all terms are placed on the LHS and may be directly controlled by NEMDE. Use of fully co-optimised constraint equations was supported by the introduction of Part 8 of Chapter 8A of the Rules. In its 2005 Statement on Transmission, the MCE outlined its policy decision in support of the fully co-optimised constraint formulation. The Commission believes that given the MCE's Statement on Transmission and the absence of any widely held view amongst participants in favour of a different method of constraint formulation, the substance of the Part 8 derogation should be moved into Chapter 3 of the Rules. The Commission also believes that all references to "inter-regional constraints" and "intra-regional constraints" could therefore be replaced with "network constraints". This would enable clauses (a) and (b) of Part 8 or Chapter 8A to be deleted without preventing NEMMCO from using fully co-optimised constraint formulation.

However, the Commission recognises that there are circumstances under which an alternate constraint formulation may be necessary to either manage counter-price flows or to manage system security. Consequently, the new Rule will be drafted to allow NEMMCO to implement an alternate constraint formulation in limited circumstances. NEMMCO should be obliged to develop guidelines for the circumstances in which this may occur and the manner in which an alternative formulation would be developed and implemented.

Information

The provision of additional, timelier or better quality information may assist participants to better the manage trading risks arising due to network congestion and may reduce the occurrence of congestion in the longer term through better locational signals for the building of new transmission and generation capacity.

Submissions to the Directions Paper generally supported increased information provision to improve congestion management. However, ETNOF noted that the provision of information is not costless and should only be required when it is meaningful and would not otherwise be provided. The Southern Generators pointed out that increased information, by itself, would not address the costs of congestion.

There is currently some information available to assist market participants to understand and manage congestion (see Appendix H). Two specific areas where the Commission considers change to be warranted are: (1) information on constraint equation development and invocation; and (2) information on the incidence and patterns of mis-pricing.

Constraint equation development and invocation

The Commission has received a number of submissions in relation to the quantity and quality of available information with respect to the development and invocation of constraint equations. Questions surround:

- The methodology and process for how constraint equations are developed, formulated and implemented by NEMMCO; and

- The real-time flow of information regarding how, why and when particular constraint equations are invoked or revoked by NEMMCO.

The method by which constraint equations are developed, formulated, and implemented is outlined in various NEMMCO documents that have no formal status under the Rules. Given the potentially significant commercial impacts of the way in which constraint formulations are developed and implemented, the Commission considers that there is a case for obliging NEMMCO to undertake these activities in accordance with published guidelines. The Commission considers that these guidelines would include a consolidation of the existing documents describing various aspects of constraints (including FCAS constraints).

The Commission considers that NEMMCO should also to be required to publish information about events other than network outages that may result in different constraint equations being formulated and/or invoked. This would help provide a richer and more continuous flow of information to participants. The nature of events for potential inclusion could be the commissioning of new network, generation and load assets, as well as the implementation of other changes, such as network support and NCAS contracts. This will help fill in the majority of the gaps in the current flow of information to participants.

Information on mis-pricing

The Commission discussed the potential for NEMMCO to publish information on mis-pricing in the Directions Paper. While some participants supported the provision of information of local nodal prices, NEMMCO considered that this would require a very substantial ongoing commitment of resources and proposed the alternative of providing mis-pricing information based on constraint shadow prices.

The Commission believes that any obligation on NEMMCO in the Rules to publish information should take into account and balance both the potential benefit to participants and the burden placed on NEMMCO. While investors base their decisions on a range of factors, the Commission believes that publication of mis-pricing information would provide some useful initial guidance and would be a proportionate response to the issue.

Transmission

Capability

As noted above, the level of network congestion at any point in time is partly a function of network capability. Factors influencing network capability include:

- The network assets in service;
- Weather events; and
- The operating behaviour of electricity producers and consumers.

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

- Investing to increase the capacity of network elements;
- Maintaining and operating network elements at their technical limits;

- Scheduling outages when the value of network capability is relatively low; and
- Engaging in other activities, such as the procurement or provision of Network Support and Control Services (NSCS).

Commission's 2006 review of transmission regulation

In 2006, the Commission reviewed and substantially reformed the Rules relating to the economic regulation of transmission in several key ways.

Service Target Performance Scheme

The Rules now provide for the AER to develop a Service Target Performance Scheme to encourage TNSPs to provide greater reliability of the transmission system at those *times* when it is most valued by transmission network users and in respect of those *network elements* that are most important to the determination of spot prices. The scheme must place between 1% and 5% of each TNSP's regulated revenue "at risk".

Transmission planning

TNSPs are obliged under the Rules to plan and develop their transmission networks to maintain power quality and reliability standards under both normal and outage conditions. The Rules require TNSPs to subject proposed network investments to the AER's Regulatory Test, to ensure their investments represent the most efficient option. In November 2006, the Commission made a Rule outlining principles for a revised Regulatory Test. The new Rule imposes much more specific principles for the "market benefits limb" of the Test, including a requirement for TNSPs to publish a request for information where they are assessing larger investments. This should help ensure that all relevant options are considered under this limb of the Test.

In March 2007, the Rules were amended to empower the Commission to direct TNSPs to undertake a Regulatory Test assessment under certain circumstances. This is known as the "Last Resort Planning Power" (LRPP). Importantly, the power of direction may only be exercised by the Commission as a "last resort".

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

- Improved locational signals to generators;
- A stronger incentive framework for TNSPs, and
- An improved national transmission planning mechanism to better coordinate and integrate the development of the national power system.

On 3 July 2007, the MCE directed the Commission to conduct a review into the development of a detailed implementation plan for a national transmission planner. The Commission has subsequently published a Scoping Paper on this matter.

Potential areas of further reform

In general, the Commission is of the view that the existing transmission regulatory regime is recently reformed and should be given time to work. Further, the specific issues relating to transmission planning and the Regulatory Test are to be examined in the context of the Commission's work on the National Transmission Planner.

However, the Commission has considered a number of specific areas where it wishes to make recommendations or observations. These are:

- Measures of transmission capability;
- The framework for the provision of Network Support and Control Services; and
- Transmission pricing.

Transmission capability

The Commission considers that more disaggregated information on network capability would improve the ability of market participants to predict the likelihood of congestion and could also provide greater general transparency to the market on what "outputs" are delivered by TNSPs. The Commission believes that work should be undertaken to develop better measures of transmission capability and that this should be given effect through obligations in the Rules. The Commission will keep this matter under review as consultation on the National Planner proceeds and would welcome participants' views on the usefulness of such measures and the party that should have responsibility for developing them.

Framework for Network Support and Control Services

Network Support and Control Services (NSCS) are those services procured and delivered by TNSPs or NEMMCO for the purpose of managing network flows to ensure secure and reliable operation of the power system. NSCS currently procured and delivered include:

- **Network Support Services** – procured by TNSPs via contracts with third parties (network support agreements (NSAs)), e.g. generators or load agreeing to be constrained on (or off) in specified circumstances; and
- **Network Control Ancillary Services** (NCAS) – procured by NEMMCO via contracts with Market Participants (not TNSPs) such as reactive power ancillary service (RPAS) in the form of voltage control or network loading control ancillary service (NLCAS) (e.g. rapid generator unit loading or load tripping scheme).

Under the Rules, NEMMCO has the ability to procure NCAS to meet their obligations under the Rules. The costs of these services are recovered as part of NEMMCO's market fees. Under the Regulatory Test, TNSPs may also use NSCS as part of meeting their own reliability obligations. However, network solutions arguably provide a TNSP with the scope to earn a greater return than non-network solutions. This is because of the ability of TNSPs to earn a regulated rate of return on their network capital expenditure, while only being able to pass-through operating expenditures (within which most NSCS would be recovered) at cost. A non-network solution may therefore represent a lower risk/lower return option for a TNSP. This difference in revenue treatment could potentially influence outcomes, although the Commission is not aware of any direct evidence that this is occurring. The Commission would welcome views on whether a change to the revenue treatment of non-network or NSCS solutions under Chapter 6A is appropriate as a means of equalising the financial incentives for TNSPs to develop network and non-network solutions, and views on what the changes should be.

The Commission also believes that NEMMCO's review of NCAS should recommence in light of the guidance provided by this Draft Report on the CMR.

Transmission pricing

The Commission's 2006 transmission review also dealt with transmission pricing. At that time, the Commission maintained a "shallow" connection charging approach for new generation. This means that generators only need to pay for the costs of their immediate connection to the transmission network and are not required to contribute to the costs of downstream augmentations. The key reason for this position was that TNSPs do not invest in network simply to alleviate congestion or to enable generators to be dispatched – TNSPs are meant to invest only where it is efficient from the perspective of the market as a whole. However, the Commission said that it would review this finding in light of the CMR.

Some market participants made submissions advocating the introduction of additional capacity or access charges into the current framework of transmission service pricing. This would provide locational signals to new generators in a way that avoided more granular pricing of congestion. For example, Delta Electricity suggested a variation of a "deep" connection approach. Under such an approach, new generators would pay the costs of downstream augmentations through access charges if their investment locations did not align with the least-cost transmission plan. Where this occurred, generators would receive firmer rights of access to the network, which would provide some form of compensation when the applicable part of the network was congested.

The Commission is not in favour of pursuing the Delta Electricity proposal for similar reasons to those set out in its 2006 pricing determination. Most importantly, generator locational decisions do not compel transmission investment. Therefore, it is difficult to see what purpose would be served by charging generators for the costs of investments that are in the interests of the market. Further, the Commission considers that the existing arrangements already provide a variety of locational signals to inform investment decisions. These include negotiated transmission charges and the fact that generator locational decisions are influenced by a series of non-price factors, such as access to fuel and water, as well as environment obligations and so on. Finally, locational signals are provided by the current provision of non-firm access to the RRP. For these reasons, the Commission believes that changes to the current transmission pricing Rules to improve locational signals on new generators are not warranted at the present time.

1 Introduction

This Draft Report presents the Australian Energy Market Commission[1] (AEMC of the Commission) proposed recommendations to the Ministerial Council on Energy (MCE) on enhanced congestion management arrangements for the National Electricity Market (NEM).

This Chapter outlines the purpose, scope and policy context of the Congestion Management Review (CMR or the Review) and describes the Commission's approach to the Review. It also outlines the structure of this Draft Report.

1.1 Congestion Management Review

In October 2005, the Ministerial Council on Energy made a notice of reference under Part 4, Division 4 of the National Electricity Law directing the Australian Energy Market Commission to consider the requirement for and scope of enhanced trading arrangements in relation to congestion management and pricing in the NEM. This review is hereinafter referred to as the Congestion Management Review (CMR or the Review).

1.1.1 Purpose of the Review

The Terms of Reference for the CMR requires the Commission to examine and report on:

- Improved arrangements for managing financial and physical trading risks associated with material network congestion, with the objective of maximising net economic benefit to all those who produce, consume and transport electricity (clause 3.1); and

- The feasibility of a constraint management regime as a mechanism for managing material congestion until those issues are addressed through investment or a boundary change (clause 3.2).

In undertaking these tasks, the ToR requires the Commission to:

- Take account of and articulate the relationship between a constraint management regime, constraint formulation, regional boundary change criteria and review triggers, Annual National Transmission Statement (ANTS) flowpaths, the Last Resort Planning Power (LRPP), the Regulatory Test, and Transmission Network Service Provider (TNSP) incentive arrangements (clause 3.2); as well as

1 The AEMC is the national body responsible for making the National Electricity Rules (the Rules) that govern the operation of the NEM. It is also responsible for market development of the NEM. The AEMC's responsibilities are specified in section 29 of the NEL.

- Have regard to previous work undertaken by CRA and the results of the limited Tumut CSC/CSP trial in consultation with the National Electricity Market Management Company (NEMMCO) (clause 3.3).[2]

1.1.2 Scope of the Review

The MCE's ToR state that the Review should develop proposals for managing the trading risks associated with material network congestion. In the Commission's view, this requires an assessment of the materiality of the costs of congestion in parallel with the consideration of various options for changes to market arrangements for congestion management. In considering the implications of congestion for participant trading risks, the ToR requires the Commission to focus on the net economic benefits to market stakeholders. The Commission has interpreted the ToR in this regard as meaning that only congestion management options that offer net benefits should be proposed. This requires a comparison of the costs and benefits of the option against the status quo counterfactual – that is, the materiality of pre-existing congestion. The ToR recognise that it would not be efficient to eliminate all transmission congestion through transmission investment, because of the likely cost of doing so compared with the benefits. This means that a degree of congestion, and the need for congestion to be managed, is likely to remain a feature of the NEM going forward.

The Commission has interpreted clause 3.1 of the ToR to require consideration of a broad range of options for assisting participants to manage trading risks associated with congestion in the NEM. These options could include arrangements that enable participants to better *manage* the trading risks of congestion directly, as well as arrangements that could reduce the *prevailing level* of congestion and thereby reducing the risks of congestion indirectly. The Commission also notes that clause 3.2 of the ToR requires specific consideration of congestion management regimes that are designed to apply to material congestion issues for limited periods until investment or boundary change addresses the constraint. This necessarily circumscribes the range of options to be considered within the Review.

1.1.3 Process of the Review

The Commission has approached this Review in an open and consultative manner. It has sought comments from stakeholders on the range of options for improving risk management for consideration and also on the extent and materiality of congestion.

In March 2006, the Commission published an Issues Paper for the Review.[3] The Issues Paper outlined the Commission's understanding of the ToR for the Review and the impacts of congestion on the market. Subsequently, in June 2006, the Commission published a "Statement of Approach" that set out the process the

---

[2] Appendix B to this Report contains a review of CRA recommendations on constraint managements and submissions received.

[3] AEMC 2006, *Congestion Management Review, Issues Paper*, 3 March 2006, Sydney.

Commission intended to take in progressing the CMR and related issues.[4] A revised Statement of Approach was published in December 2006.[5] Finally, in March 2007, the Commission published its Directions Paper, setting out some preliminary findings on materiality and a discussion of the options it considered worthy of closer examination.

1.1.4 Criteria for the Review

The requirement in the ToR to focus on the net benefits to market participants of potential arrangements for managing congestion is similar to the obligation imposed on the Commission in the NEL to pursue the NEM Objective. The NEM 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."[6]

Therefore, the Commission considers that it is appropriate to approach this Review by assessing the various options for change against the NEM Objective.

The likely economic efficiency effect of an option or proposal on the market is an important element of applying the NEM Objective. Economic efficiency is commonly defined as having three elements:

- Productive efficiency – meaning the electricity system is operated on a "least cost" basis given the existing and likely network and other infrastructure. For example, generators should be dispatched in a manner that minimises the total system costs of meeting consumers' demands;

- Allocative efficiency – meaning electricity production and consumption decisions are based on prices that reflect the opportunity cost of the available resources; and

- Dynamic efficiency – meaning maximising ongoing productive and allocative efficiency over time, and is commonly linked to the promotion of efficient longer term investment decisions.

The Commission believes that promoting the conditions for competitive conduct in the NEM will often, though not always, spur improvements in all three dimensions of efficiency.

In addition, the Commission has taken the view that the NEM Objective is not solely focussed on a technical approach to the promotion of efficiency. Rather, the NEM Objective has implications for the means by which regulatory arrangements operate

[4] AEMC 2006, *Congestion Management Program – Statement of Approach*, June 2006, Sydney.

[5] AEMC 2006, *Congestion Management Program – Statement of Approach*, June 2006, Sydney.

[6] Section 7, National Electricity Law.

as well as their intended ends. This means that the Commission also seeks to promote stability and predictability of the regulatory framework. This, in turn, means to:

- Minimise operational intervention in the market – intervention in the operation of competitive markets should be limited to circumstances of market failures. Further, the Commission recognises that market failure is only a necessary and not sufficient condition for regulatory intervention;

- Promote changes that are likely to be robust over the longer term – other things being equal, the Rules for the dispatch and pricing of the market should be sufficiently stable and predictable to enable participants to plan and make both short- and long-term decisions; and

- Promote transparency in the operation of the NEM – to the extent that intervention in the market is required, it should be based on, and applied according to, transparent criteria.

In addition, the Commission seeks to promote changes that are consistent with higher-level public policy settings and move the market in a direction of positive and self-reinforcing incremental improvements. These requirements are founded on the principles of good regulatory design and practice, which the Commission believes is central to its task in furthering the NEM Objective.

The Commission has applied this criteria in its developing its recommendations for improving current market arrangements for congestion management. In addition, the Commission has considered the implications of the various options for the quality, security and reliability of the national electricity system.

1.1.5 Submissions on the Commission's approach to the CMR

A number of submissions commented on the analysis and options presented by the Commission in the Directions Paper. Most of submissions agreed with the thrust of the Directions Paper, although several stakeholders disagreed with certain aspects of the Commission's approach.

The Major Energy Users (MEU) considered that the Commission's approach was too focused on improving risk managements mechanism, without proper consideration of the cost implications to the end consumers of such mechanisms. The Electricity Users Association of Australia (EUAA) also stated that more consideration needed to be given to how risk management mechanisms impact on end-consumers.

The Southern Generators considered that the Directions Paper took an overly narrow view of the scope of the Review. They submitted that any option that can manage current and future congestion without further development or regulatory intervention should form part of this Review and that the Commission should not be limited to evaluating purely localised interim solutions.

In response to these concerns, the Commission draws participants' attention to the MCE's ToR. The ToR requires consideration of the physical ***and financial*** trading risks of congestion and limits the Commission to the consideration of congestion management options designed to apply to specific instances of ***material*** congestion issues for defined periods only. It was clearly not the MCE's intention for the Commission to assess options that required radical reform of the current market arrangements.

1.2 Policy Context for the Review

The Commission has developed its draft recommendations under the Review in the context of a number of important related reforms to market arrangements and the regulation of transmission companies that have occurred since October 2005. The congestion management regime for the NEM should be considered as these collective set of arrangements, rather than just these Review proposals in isolation. The Commission has approach this Review in a co-ordinated and integrated manner and have developed the recommendations in this Report to complement these reforms.

The key changes since October 2005, which set the context for the CMR draft recommendations are:

- **Rule changes in respect of the Economic Regulation of Transmission Services**: In November 2006, following a process of consultation and review, the Commission made a set of change to the Rules to put in place a new regime of economic regulation for transmission. This establishes the incentive framework for transmission companies, including to provide services in support of a competitive wholesale market. An important element of this process, from the perspective of congestion management, is the ongoing develop of specific incentive schemes by the AER.[7]

- **Last Resort Planning Power (LRPP)**: In March 2007, the Commission made a change to the Rules to put in place the LRPP. This enables to Commission to direct a party to undertake a Regulatory Test assessment in respect of a identified new network investment. Its purpose is to ensure timely and efficient inter-regional transmission investment.[8]

- **Review of Regulatory Test Principles**: The Commission made a Final Rule Determination on the Rule change for the Reform of Regulatory Test Principles on 30 November 2006.[9] The Rule change will allow the Regulatory Test to operate more effectively, providing greater policy guidance for the promulgation of the Test and increasing the certainty and transparency of the application of the Test. The Rule makes the market benefits limb of the Test simpler, through the provision of an information mechanism for alternative projects and requiring that the comparison of the proposed investment be made only against identified alternatives rather than all possible alternatives. The Commission considers that

7 AEMC 2006, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006, Rule Determination, 16 November 2006, Sydney, and AEMC 2006, National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006, 21 December 2006, Sydney.

8 AEMC 2007, National Electricity Amendment (Transmission Last Resort Planning) Rule 2007, Rule Determination 8 March 2007, Sydney and AEMC 2007, Last Resort Planning Guidelines, 10 July 2007.

9 AEMC 2006, Reform of Regulatory Test Principles, Rule Determination, 30 November 2006, Sydney.

this will lead togreater incentives for TNSPs to utilise the market benefits limb of the Regulatory Test and this will facilitate investments to relieve congestion.

- **Comprehensive Reliability Review**: The Commission has requested the Reliability Panel to undertake a comprehensive and integrated review of the effectiveness of NEM reliability settings, including whether there may be a need to improve or change them. The panel is focusing on whether an adequate level of generation and bulk transmission is made available. In June, an additional request was made by the MCE to provide advice on strengthening the market's ability to manage generator inputs. The panel has release a second interim report in August 2007, and intends to publish its final decisions in November 2007.[10]

In addition, the Commission has noted and considered the recommendations made by the Electricity Reform Implementation Group (ERIG) in January 2007.[11] ERIG is a body formed through the Council of Australian Governments (COAG) and have review a range of matters, including transmission and energy financial markets. In particular, the Commission notes ERIG's position in favour of the need for stronger locational signals for generation investment, notwithstanding the existence of non-price signals and the need for improved incentives for both efficient operation of the existing transmission network and better co-ordination of investment in the transmission system on a national basis.

In light of ERIG's findings, the MCE requested that the Commission develop a detailed implementation plan for the national transmission planning function, as specified in the COAG decision of 13 April 2007.[12] The Commission published a Scoping Paper in August 2007 as the first stage in this process.[13]

1.3 Structure of this Draft Report

This Draft Report is structured as follows:

- Chapter 2 provides the analytical framework for the Review by defining congestion, discussing its impact and describing how it is currently managed in the NEM;

- Chapter 3 contains the Commission's assessment of the materiality of the impact of congestion on economic efficiency within the NEM. This includes evaluating the data on the historical incidence of congestion and assessing the future trend in congestion and assessing available measures on the costs of congestion;

The subsequent chapters each evaluate the different classes of options for improving congestion management arrangements. The Commission has

---

10 AEMC Reliability Panel, Comprehensive Reliability Panel, Second Interim Report, August 2007.

11 The ERIG Report is available at http://www.erig.gov.au.

12 MCE letter to the AEMC, 3 July 2007.

13 AEMC, National Transmission Planner: National Transmission Planning Arrangements Scoping Paper, August 2007.

considered the merits of each option in light of its potential benefits and costs in the context of the prevailing materiality of congestion.

- Chapter 4 assesses the options relating to more localised market pricing arrangements for generation and load, which effectively seek to reflect the cost of transmission congestion in locational price differentials;
- Chapter 5 discusses risk management and addresses options for improving the existing Settlement Residue Auction instrument for the management of inter-regional trading risks;
- Chapter 6 discusses the relationship between constraint formulation and potential changes to the Rules on information provision that would aid in the management of congestion by participants; and
- Chapter 7 considers the role of transmission services in both directly limiting the incidence of congestion, as well as in enabling participants to better manage trading risks due to congestion.

There are a number of supporting appendices which provide more detail on the issues raised in the chapters. These are referenced at the relevant points. The Commission also intends to publish two supporting technical papers on the issues discussed in Chapter 4, and in light of submissions on the Draft Report, to publish exposure drafts of the Rule changes implied by the recommendations in this Draft Report.

1.4 Request for Submissions

Interested stakeholders are invited to make comment on the Commission's reasoning and proposed arrangements for congestion management presented in this Draft Report.

Submissions should be received by 9 November 2007. Submissions can be sent electronically to submissions@aemc.gov.au or by mail to:

Australian Energy Market Commission

PO Box A2449

Sydney South NSW 1235

Following consideration of submissions and further analysis the Commission will prepare its Final Report for submission to the MCE.

This page has been intentionally left blank

2 Context

This Chapter provides a context and framework for the issues discussed in subsequent chapters. It explains:

- What congestion is, and why it occurs;
- How congestion is managed currently in the NEM; and
- How congestion, and its management, might impose economic costs.

The Chapters that follow set out the evidence on the materiality of congestion in the NEM (Chapter 3), and explain the Commission's views and draft recommendations on what particular aspects of the ways in which congestion is managed should be changed (Chapters 4 to 7).

2.1 What is congestion?

Broadly speaking, congestion occurs when there is a "bottleneck" on the transmission network. Such bottlenecks arise when the ability of the network to accommodate the power flows emerging from the dispatch process has been reached. The power flows resulting from the dispatch process are dependent on the interaction of the demand for and supply of electricity across different locations in the NEM. For example, if high demand in location B is met by supply in location A, power will tend to flow from A to B across the various network paths in between.

The ability of the network to handle power flows is referred to as its "capability". Capability is a dynamic variable that depends on both the technical design limitations of individual network elements – known as their "capacity" – as well as the way in which those network elements are operated collectively under different power system conditions at each point in time.

For a given network capacity, network transfer capability is governed by four factors:

1. Patterns of generation and demand;
2. Ambient weather conditions;
3. Availability of transmission elements (e.g. transmission lines and transformers being in service); and
4. The availability of contracted NSCS (e.g. reactive power capability, network loading control).

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

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

Issues surrounding transmission capability and the role of different parties in promoting greater capability are discussed further in section 2.2.3 and Chapter 7 below.

2.2 How is congestion currently managed in the NEM?

As noted above, congestion management is necessary to maintain the physical and operational security of the power system. How this is done has important implications for both the physical operation of plant and financial trading in the market, in both the short term and the long term.

The Rules contain no single mechanism for managing congestion. In broad terms, Rules relating to congestion management can be separated into three categories:

- The Rules governing the dispatch of generation, including the way the physical power system is represented in NEMDE, through constraint equations;
- The Rules governing pricing and settlement, including the way prices are determined and settlement is carried out for each market participant in the event of congestion within or between regions; and
- TNSP activities, including short-term arrangements for transmission element availability and transfer capability and long-term investment in network assets and alternatives.

2.2.1 Dispatch and constraint formulation

NEMMCO's role as market and system operator includes managing the process that determines how much each generator is required to generate (i.e. dispatched) at any particular point in time. NEMMCO recalculates these quantities every five minutes to ensure that load continues to be met safely and securely. NEMMCO has a 'dispatch engine' (NEMDE) to undertake this calculation, using a mathematical technique known as linear programming. NEMDE calculates the least-cost way of dispatching generation to meet load, based on the prices and quantities contained in the bids and offers submitted by market participants, while remaining within the predefined security and reliability parameters that are set out in the Rules.[14]

These parameters can be broadly described as either 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

[14] Rule 3.8.1 details the responsibilities of NEMMCO regarding the central dispatch process. This Rule states that the central dispatch process should aim to maximise the value of spot market trading on the basis of dispatch bids and offers.

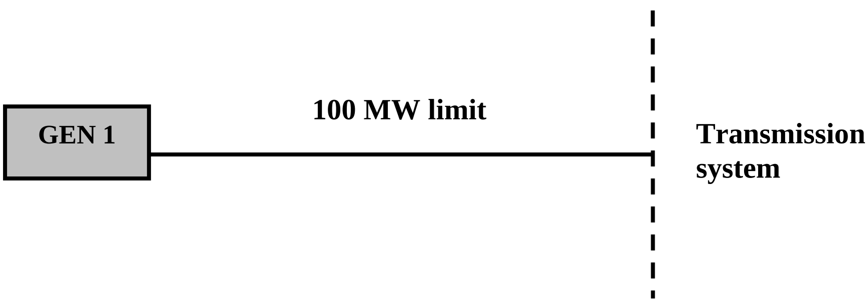
clearance above ground level must exceed certain minimum heights to ensure both public safety and power system security; and

- *Stability limits* refer to the need to keep the transmission system operating within design tolerances for voltage, with the ability to recover from disturbances, taking into account interaction control systems and other technical characteristics that are important to keep the power system intact. 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 ensure limits are not exceeded in order to maintain power system security and reliability.

The information characterising network capability and security and reliability parameters is contained within a set of "network constraint equations" within NEMDE. Each network constraint equation is a mathematical representation of the way in which different variables affect flows across particular transmission limits. A network constraint is thus a limitation imposed on the market dispatch relating to the physical capability of the transmission network in the relevant five-minute dispatch interval. There is a separate constraint equation for each limitation imposed on the dispatch.

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



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

GEN 1 < 100

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

GEN 1 = 0

To illustrate further, the simple example above can be extended to include load. If a load (LOAD 1) were located at the same location as GEN 1, the flow along the line with the limit of 100MW would be determined by the generation output net of the amount of electricity consumed by LOAD 1. Hence, the constraint equation would take the form: [15]

GEN 1 – LOAD 1 < 100

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

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

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

This is the so-called "fully co-optimised" form of constraint equation. Generator output terms and interconnector flow terms tend to appear on the LHS, while (non-

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

dispatchable) load terms and terms relating to the limits of particular transmission elements tend to appear on the RHS.[16] Chapter 6 discusses alternative ways of formulating constraints in more detail and sets out the Commission's recommendations in this area.

The extent to which increases in a particular term on the LHS utilises the limited flow allowed by a constraint is reflected in its "coefficient" in the constraint equation. For example, a particular constraint equation may have two generator terms on the LHS, one with a coefficient of 0.3 and the other with a coefficient of 0.9. This means that the output of the generator with the 0.3 coefficient would utilise less of the allowable flow on the applicable network element(s) than the output of the generator with the 0.9 coefficient. This in turn implies that the generator with the 0.3 coefficient could produce more power without violating the constraint than the generator with the 0.9 coefficient. A negative co-efficient for a generator[17] means that its output helps relieve the constraint.

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

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

1. By NEMDE changing the level of variables under its control — such as generation, dispatchable loads and interconnector flows — so that the RHS limit is not violated. That is, by NEMDE adjusting one or more of the LHS terms in a constraint, such as by constraining-on or –off particular generators; and

2. By raising the RHS limit of a constraint, thereby relaxing the constraint so that it no longer binds (or binds at a higher level). In order to raise the RHS of the

---

[16] NEMMCO's responsibilities regarding constraint formulation are set out in Rule 3.8. Specifically, Rule 3.8.10 states that NEMMCO must determine constraints on dispatch and that these must be represented in a form that can be later reviewed. Also, Rule 3.8.13 specifies that NEMMCO must publish the parameters used for modelling of the constraints.

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

constraint, it is often necessary to change the value of parameters that influence the RHS limit value. Many of these limit parameters are outside the control of the dispatch engine, and require some external action by NEMMCO or a TNSP in order to change the parameter values.

Section 2.2.3 and Chapter 7 below discuss the obligations and incentives on NEMMCO and the TNSPs to enhance capability in these ways.

Capturing network capability through constraint equations illustrates the point that congestion is what occurs when a constraint equation binds.[18] This provides two alternative ways of characterising congestion. From one perspective, congestion can be described by identifying particular transmission limits that have been reached (and likewise identifying the associated transmission equipment or circuits that cannot accommodate increased power flow). Hence, congestion can be viewed as occurring on a particular point (or across a particular "boundary") on the transmission system. From another perspective, congestion can be viewed as the constraining influence of a network limit on the optimality of generation dispatch. For constraint equations that contain at least one interconnector flow term (in the order of 75% of constraint equations in a normal dispatch interval), the binding of the constraint would affect generation dispatch in at least two regions of the NEM. This illustrates the point that constraints can have far-reaching effects on dispatch, and therefore, on pricing and settlement outcomes. This is discussed further in the next sections.

Appendix C to the Report provides further explanation on the Types of Constraints within the NEM.

2.2.2 Pricing and settlement

The preceding section explained that NEMMCO's dispatch engine attempts to dispatch generation to meet load in the least-cost way (based on participants' bids and offers), consistent with the prevailing set of constraints in that dispatch interval. This implies that the dispatch process takes account of not only the price at which participants make bids and offers, but also the location (or "node") at which participants are situated within the transmission network.

[18] A constraint binds when the LHS = RHS. When this occurs, the "shadow price" of the constraint is positive (the "shadow price" is also referred to as the "constraint marginal value" or "dual price"). Conversely, when the constraint is not binding i.e. LHS<RHS, the shadow price is zero. The shadow price represents the marginal cost to the objective function of marginally relaxing the constraint. The objective function in NEMDE is to minimise the cost of supplying electricity to meet demand, subject to security and physical constraints, where 'costs' relate to offers rather than underlying "resource costs" (i.e. the SRMC and/or opportunity costs of generation). Therefore, the shadow price on a binding constraint represents captures the marginal value (based on offers) of reducing the total costs of meeting demand by marginally easing the constraint. This offer-based marginal value will accord with underlying (or "true") economic value, based on resource costs, if generator offers are reflective of resource costs. The dispatch process will yield an economically efficient outcome if the pattern of generation arising from offers aligns with the least cost dispatch based on underlying resource costs. Electricity markets aim to achieve economically efficient dispatch by creating competitive pressures that result in incentives for generators' offers to correctly reflect their underlying resource costs.

However, the pricing and financial settlement of participants is implemented on a regional basis in the NEM.[19] There are currently six regions in the NEM: Queensland, New South Wales, Snowy, Victoria, Tasmania and South Australia. From 1 July 2008 this number will be reduced to five, with the abolition of the Snowy region and the expansion of the current New South Wales and Victoria regions.[20] Each region contains many nodes, where generators are loads are connected.

A settlement price is calculated separately for each region for each thirty minute trading interval. This is known as the regional reference price (RRP). The RRP is the cost (based on bids and offers) of supplying an additional unit of electricity at a particular node in the region known as the Regional Reference Node (RRN).[21] The RRNs are generally located in the major load centres in each region, such as at or near the capital city. All generators in a region receive the applicable RRP on the volume of energy for which they are dispatched across the six dispatch intervals that comprise each trading interval (ignoring losses), regardless of whether or not they are located at the RRN. Similarly, all loads in a region pay the applicable RRP for the amount of electricity they consume in the relevant trading interval (again ignoring losses).

When congestion occurs, it can cause differences in the marginal cost of supplying energy at different locations. To the extent this leads to different marginal costs of supply at different RRNs, the result would be a divergences of RRPs.[22] This would typically be reflected in cheaper generation being "backed off" in low-priced regions as a result of a constraint binding, and more expensive generation being dispatched in high-priced regions.

As in other markets, these inter-regional price differences play an important signalling role in the NEM. In the short term, they provide signals to generators in high-priced regions to produce more and for loads to consume less, relative to generators and loads located in low-priced regions. Over time, price differences can encourage efficient decisions by market participants concerning when and where to invest in generation and load assets. Inter-regional price differences also create financial trading risks for participants. These risks and the way they are presently managed in the NEM is discussed in section 2.3 below.

---

19 Rule 3.15 identifies and describes settlement transactions that are managed by NEMMCO. This Rule is extensive and sets out the financial responsibilities of market participants, the process for the calculation of adjusted energy amounts and trading amounts for both spot market transactions and ancillary service transactions. It also sets out the process for compensation payments and details other payments such as VoLL or market floor price compensation. The Rule identifies the process for payment by and to market participants, including detail on statements, disputes, electronic finds transfers and the default procedure.

20 AEMC 2007, *Abolition of Snowy Region*, Final Rule Determination, 30 August 2007, Sydney.

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

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

However, in the NEM's regional pricing and settlement structure, congestion can also cause differences in the marginal cost of supply within a Region, between the RRN and other nodes in the region.[23] The marginal cost of supply at each node other than the RRN is referred to as the local or "pseudo" nodal price, and this is calculated as a by-product of the dispatch process. In other words, participants are effectively dispatched on the basis of a comparison between their bid or offer price and their local nodal price. If their bid or offer price is less than their local nodal price, they will be dispatched to the corresponding volume; if their bid or offer price is greater than their local nodal price, they will not be dispatched.

To the extent that congestion causes divergences between the RRP and local nodal prices in the NEM, this impact is not reflected in differences in the prices paid or received by participants located at those other nodes in the region. As noted above, all generators (and loads) within a region receive (pay) the same price (the RRP) for the energy they are dispatched to produce (consume) within a trading interval regardless of whether their implied local nodal price is the same as their RRP. This disjoint between the implied nodal prices yielded by the dispatch process and the RRPs used for settlement is commonly referred to as "mis-pricing". Mis-pricing can create risks for participants and promote behaviours that reduce economic efficiency, as discussed further in section 2.3 below.

2.2.3 TNSP and NEMMCO influences on congestion

Both the TNSPs and NEMMCO can influence the capability of the transmission network and consequently the level and impact of congestion. This section discusses the means by which TNSPs and NEMMCO have this influence and Chapter 7 assesses the scope for improving transmission performance in order to alleviate the extent and risks of congestion.

Market participants contract with TNSPs for connection to the transmission network. These agreements provide non-firm physical (and financial) access to the market for generators. There is no guarantee of individual generators being dispatched and no compensation for not being dispatched.[24] The risk of not being dispatched – and the signals this provides to existing and prospective market participants – is an important element of how congestion is managed in the NEM.

As noted in section 2.1 above, congestion arises when network transfer capability it at its limit. Section 2.1 also highlighted that there is an important distinction between network *capacity* and *capability*. *Capacity* refers to fixed design limitations on individual network elements (e.g. lines, transformers, SVCs). Capacity can be increased by investment in network assets. *Capability* refers to the variable ability for a set of network elements to transfer energy under the prevailing power system conditions (and implied security status).

---

[23] Chapter 4 explains how the extent of mis-pricing for any particular point on the network, at any particular point in time, can be calculated.

[24] 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.

Congestion reflects a lack of *capability*, not necessarily a lack of *capacity* and an increase in network capacity will only alleviate congestion if it also results in an increase in the transfer capability of the network. The behaviour of TNSPs in operational and investment timescales can impact on the capacity and the transfer capability of the transmission network at any point in time. Efficient behaviour by TNSPs is therefore an integral part of the congestion management regime because both long-term investments in capacity as well as short-term actions that affect transfer capability, can affect the frequency, location and level of network congestion.

The Rules provide financial incentives for TNSPs to implement operational actions that relieve congestion in the short-term and extract the maximum efficient level of transfer capability out of the existing network capacity.[25] The operational costs associated with these actions are recovered from market customers via a combination of regulated transmission charges and non-market ancillary service charges (NCAS fees).

In the longer term, the Rules governing the treatment of capital expenditure in the determination of transmission revenues affect the incentives of transmission companies to efficiently invest to increase transmission capacity and transfer capability.

2.3 What types of costs are imposed by congestion and its management?

Congestion and the way it is managed in the NEM imposes a number of risks and costs on producers, consumers and transporters of electricity in the market.

This section discusses both:

- The direct costs of congestion – arising from higher-cost dispatch; and
- The indirect costs of congestion – arising from the physical and financial trading risks of congestion faced by participants.

Policy options for reducing the level of congestion or improving the way congestion is managed are assessed in Chapters 4 to 7.

2.3.1 Direct costs of congestion

As congestion refers to the inability of the transmission network to accommodate the power flows emerging from the dispatch process, the most direct impact of congestion is to require the dispatch of higher cost plant to meet demand than would otherwise be the case. For example, congestion may require the dispatch of a generator with resource costs of $40/MWh to meet load, instead of a generator with resource costs of $10/MWh. This would represent a loss of economic welfare to the market as a whole of $30/MWh, compared to the case where network capability was higher and the congestion did not arise.

---

[25] See Chapter 7., section 7.2.

2.3.2 Indirect costs of congestion

Congestion also imposes costs through its effect on the trading risks faced by participants. These trading risks largely derive from participants' entry into financial derivative contracts.

2.3.2.1 Background – derivative trading in the NEM

The NEM is a "gross pool" market, in that virtually all electricity must be bought and sold through the wholesale spot market operated by NEMMCO.[26] Therefore, participants tend not to enter contracts for the physical delivery or receipt of power. However, participants do enter financial contracts in order to hedge their exposures to volatile wholesale spot prices. Financial contracts are used to effectively set or limit the price ultimately paid or received for wholesale electricity in the NEM by retailers and generators, respectively.

For example,

- 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 generators and retailers to hedge their spot price exposures by entering financial contracts with one another.

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

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

[26] The Rules provide certain exemptions, largely related to on-site generation.

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 by volume occurs using OTC contracts rather than through exchange traded contracts.[27]

As noted in section 2.2 above, when constraints bind, this may lead to either or both of the following:

- Differences in RRPs caused by differences in the marginal cost of supply at different RRNs; and

- Mis-pricing of generation and load within a region caused by differences between the RRP and implied local nodal prices.

The first of these impacts gives rise to financial trading or "basis" risk for participants, to they extent they have entered financial contracts that are settled against the RRPs of other regions. The second of these impacts gives rise to physical or "dispatch" risk for generators, because it means that generators may not be dispatched even if they are willing to supply power at or below the prevailing RRP. This could lead to generators having to make "unfunded difference payments" on their contracts. Alternatively, generators could be dispatched even if they are not willing to supply electricity at or below the RRP. Furthermore, to the extent a generator is financially contracted in another region, it may be subject to *both* basis risk and dispatch risk.

These risks are discussed in more detail in the following sections. A key point to note is that there may be a trade-off between basis risk and dispatch risk. This is because more "granular" spot market pricing arrangements – in which more RRPs are calculated at different locations – may reduce mis-pricing and hence reduce dispatch risk, but may simultaneously increase the basis risk that participants need to manage. This, in turn, could increase the complexity and unpredictability of the market arrangements. Striking the right balance in amongst these trade-offs is a key theme of Chapter 4.

2.3.2.2 Costs of basis risk

Where participants in the NEM have entered financial contracts that are settled against RRPs in other regions, they are vulnerable to differences between their local RRP and the RRP at which those contracts are settled. For example, a generator in Victoria is settled in the spot market at the Victorian RRP. However, if such a generator has entered into a swap contract with a retailer in NSW and this contract is settled at the NSW RRN, the generator faces a risk that Victorian and NSW RRPs could diverge due to binding constraints. If the NSW RRP rises above the Victorian

[27] However, between 2002-03 and 2006-7, there has been a significant increase in the total volume of exchange traded contracts and the relative decline in the proportion of broker traded OTC contracts. See PriceWaterhouseCoopers (2006), "New Perspectives on Liquidity in the Financial Contracts Electricity Market", PWC, Sydney, November.

RRN, the generator could be in a position where it has to made difference payments (equal to the difference between the NSW RRP and the strike price of the swap multiplied by the contract quantity) to the NSW retailer, even though the generator has only received the (lower) Victorian RRP on its actual output.

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

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

Tools are available to enable participants to hedge the inter-regional price differentials caused by congestion. When RRPs diverge, inter-regional flows create IRSR funds, which are equal to the difference between the RRPs of the destination (i.e. importing) and source (i.e. exporting) regions, multiplied by the volume of flow and time duration.[28] Settlements of inter-regional power flows are made from the IRSR funds. Shares to a proportion of the IRSR fund for each directional interconnector are regularly sold at Settlements Residue Auction (SRA). Participants can acquire IRSR units to hedge the basis risk of contracts referenced to a different region's RRP.

However, as discussed in Chapter 5, IRSR units do not typically provide a firm (i.e. reliable) hedge against contract exposures arising as a result of inter-regional price differentials. To the extent that IRSR units provide an imperfect hedge for basis risk, the actual or potential presence of congestion may deter participants contracting across regional boundaries and/or demanding higher contract premiums.

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

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

2.3.2.3 Costs of dispatch risk

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

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

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

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

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

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

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

- Constrained-on generators being incentivised to make offers up to the maximum price of $10,000/MWh (or bidding unavailable); and

- Constrained-off generators being incentivised to make offers down to the market floor price of -$1,000/MWh (or bidding inflexible).[29]

Clearly, such offer prices would not reflect generators' underlying resource costs of production. In an environment of such "disorderly bidding", the economic

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

efficiency properties of the bid-based merit-order dispatch approach used in the NEM may be undermined. For example, a generator with a resource cost of \$30/MWh that seeks to avoid being constrained-on by offering its capacity at \$10,000/MWh may cause the dispatch of a generator with a resource cost of \$50/MWh. This leads to a short term loss of economic welfare to the market of \$20/MWh multiplied by the output of the higher-cost generator. Similarly, a generator with a resource cost of \$100/MMh may avoid being constrained-off by offering its capacity at -\$1,000/MWh, thereby displacing a generator with a resource cost of \$30/MWh. This behaviour would cause a welfare loss of \$70/MWh over the displaced output.

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

In the longer term, dispatch risk caused by mis-pricing may distort generators' locational investment decisions. For example, to the extent a proponent of a generation project believes it can manage dispatch risk through disorderly bidding, it may be tempted to invest in a relatively high-cost plant in a congested part of the network. Alternatively, if disorderly bidding is unlikely to enable a prospective generator to manage dispatch risk, then even an efficient new entrant may be deterred from investing. Either way, dynamic efficiency would be compromised.

For these reasons, the extent of mis-pricing may provide a useful indication of the potential productive and dynamic costs of congestion. Estimates of the incidence and materiality of congestion in the NEM are discussed in Chapter 3.

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

3 Materiality of congestion in the NEM

This chapter sets out the evidence on the significance and persistence of congestion in the NEM considered by the Commission through the course of this Review. An understanding and assessment of the materiality of congestion and its costs is required to determine what, if any, changes should be made to the current arrangements. In its assessment, the Commission has considered both the data on the prevalence, duration and location of congestion as well as the indicators of the economic costs of congestion.

The first part of the chapter considers the evidence on the prevalence of congestion. The second part of the chapter considers the evidence on the economic materiality of prevailing congestion, including new modelling work commissioned to inform this draft decision report. This chapter also canvasses views raised in submissions from market participants on the materiality of congestion in the NEM.

3.1 Prevailing patterns of congestion in the NEM

There is a large body of evidence on prevailing patterns of congestion in the NEM and how these patterns have evolved over time. The sources of evidence are the annual AER reports on the indicators of the market impact of transmission congestion, the NEMMCO SOO-ANTS and work provided by Dr. Biggar and NEMMCO on the patterns of mis-pricing in the NEM.[30]

This evidence is detailed and discussed extensively in Appendix D. This section of the chapter summarises and discusses the key themes. In conjunction with this Draft Decision Report, NEMMCO has published a report containing additional analysis on the nature of mis-pricing across the NEM. This analysis builds on the previous work published with the Commission's Directions Paper.[31]

3.1.1 Incidence and nature of congestion in the NEM

Appendix D contains a detailed review of the data published by both the AER and NEMMCO on the hours of binding constraints and on cumulative marginal values for inter- and inter-regional constraints.

This evidence shows that the nature of congestion in the NEM can be quite unpredictable, with both the location of the significant constraints and the total duration of each constraint binding changing significantly on an annually basis. It seems that most constraints have a relatively short "life–cycle", in that they may cause some mis-pricing for one or two years before being largely addressed by

30 AER, 'Indicators of the market impact of transmission congestion' reports for 2003/04, 2004/05 and 2005/06; NEMMCO, Statement of Opportunities – Annual National Transmission Statement (SOO-ANTS), October 2006; and NEMMCO, Impact of intra-regional constraints on Pricing study, March 2007.

31 NEMMCO, Impact of Intra-Regional Constraints on Mis-Pricing, Additional Results. September 2007·

investment in transmission or generation infrastructure, or through changed operating strategies by participants.

In its advice to the MCE in 2004, CRA also noted that constraints have an identifiable life-cycle. Consideration of the life-cycle of a constraint is crucial in considering the appropriate policy response.[32]

There are a few instances where congestion at a location has remained persistent. The Snowy Region is the main location where congestion has remained persistent over the past five years. The dominant view of opinion at the Industry Leaders Strategy Forum, was that, except for the Snowy Region, congestion did not appear to be a major problem in the NEM at the present time.[33]

The historical data in the NEMMCO SOO-ANTS show that inter-regional constraints bind far more than often intra-regional constraints. In 2005/06, there were approximately more than three times as many hours binding of inter-regional constraints as there were of intra-regional constraints.[34] Flows from Victoria to South Australia have consistently accounted for the highest number of hours binding of an inter-regional constraint, followed by the Queensland to New South Wales (QNI) interconnectors. During the period 2001 to 2006, Queensland consistently had the highest prevalence of binding hours of intra-regional constraints.

The data also show that there has been some variation in the trends and duration of congestion across the NEM regions. The evidence illustrates that the incidence of congestion has decreased within Victoria, while it has increased steady in New South Wales and Queensland.

Another finding from the review of AER and NEMMCO data is that there need not be a direct relationship between the number of hours binding and the market impact of a constraint. Some constraints can bind for long durations but have little material impact on dispatch or price, while other constraints bind for a short time but have a significant market impact. For example, the Heywood interconnector (between South Australia and Victoria) has the highest incidence of hours binding for NEM interconnectors – this constraint was binding for over 16% of the time during 2004/05 and 2005/06. However the cumulative marginal value of this interconnector binding has been relatively low, suggesting that it has very little impact on dispatch costs.

The evidence also suggests that specific events can greatly affect the reported level of constraints binding. For example, the drought in Victoria during 2005/06 led to increased transfers from Snowy to Victoria, which in turn led to more binding constraints on the Snowy to Victoria interconnector. Further, the data indicate that most of the impact of congestion is experienced on only a few days of each year triggered by specific conditions (e.g. outages or peak demand conditions). This can

[32] CRA 2004, NEM Regional Boundary Issues: Modelling Report, report to MCE, 16 September 2004.

[33] AEMC, Congestion Management Review, Industry Leaders Strategy Forum, October 2006, Sydney.

[34] Total hours binding for inter-regional constraints in 2005/06 was 7958, for intra-regional constraints the amount was 1830.

mean that congestion is difficult for market participants to predict, and hence can creates risks that are difficult for market participant to manage.

The data also show that while regional pool prices are converging on average, they can often diverge significantly at times of high price levels. ERIG attributed this divergence principally to poor interconnection performance.[35]

3.1.2 Extent of mis-pricing in the NEM

To assist its assessment of materiality, the Commission requested Dr. Darryl Biggar to develop a measure of the significance of intra-regional congestion.[36] Dr. Biggar sought to measure the materiality of congestion within regions by calculating the frequency, duration and magnitude of deviations between the theoretically "correct" price at each connection point (the nodal shadow price) and the RRP. Nodal shadow prices for each connection point were calculated using data from the NEMDE.[37]

Dr. Biggar found that the NEM-wide incidence of mis-pricing (both in terms of the average hours of mis-pricing and the number of generator connection points experiencing mis-pricing) had been increasing since 2003/04. He considered that mis-pricing was a frequent and enduring issue at a relatively large number of connection points, stating that around 95 connection points in the NEM have been mis-priced for more than 100 hours per annum on average over the last three years. Dr Biggar concluded that if creating new regions were the only mechanism for managing intra-regional congestion and eliminating mis-pricing, the number of pricing regions in the NEM would need to increase substantially, to possibly around 70.

Dr Biggar's measure of mis-pricing provides an indication of the extent to which different generators may be affected when constraints bind.[38] However, his analysis did not seek to assess how generators may have bid if they had faced the correct locational price and did not attempt to measure the full effect of congestion on the economic efficiency of dispatch.

The Commission considered that further analysis was required to understand the implications of Dr. Biggar's analysis. This included:

1. investigating what were the factors behind the increasing incidence of mis-pricing, in order to assess whether the increasing trend is likely to continue into the future.

---

35 Energy Reform Implementation Group, Review of Energy Related Financial Markets, Electricity Trading Report, November 2006.

36 Biggar, D., How significant is the mis-pricing impact of intra-regional congestion in the NEM?, 25 October 2006 (available on the AEMC website).

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

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

2. calculating the relative proportion of mis-pricing caused by system normal and outage events, and

3. understanding the economic costs of mis-pricing.

The Commission considered that understanding these issues would enable it to assess likely future trends of mis-pricing and the appropriate policy response.

The Commission subsequently made a request to NEMMCO to review the results in Dr. Biggar's paper. NEMMCO agreed to extend the analysis to cover a larger study period (from 2001/02 to 2005/06) and perform some analysis to identify the causes behind any trends in mis-pricing.

NEMMCO's preliminary study confirmed Dr. Biggar's findings that there has been an increasing trend in mis-pricing from 2003/04 onwards for the NSW, Queensland and South Australian regions, with the Victorian region showed decreasing trend. However the study also showed that over the analysis period from 2001/02 to 2005/06, the number of connection points being mis-priced was fairly steady. Across all regions, the NEM-wide number of mis-priced connection points remained within a band of 120-140. Regarding the average annual duration of mis-pricing at each of those connection points, there was a big fall from about 160 hours in 2001/02 to 40 in 2002/03. This was followed by a gradual increase to just over 60 hours in 2004/05 and then to about 110 in 2005/06. The average duration of mis-pricing was highest in NSW and Queensland and lowest in Victoria and Tasmania.

NEMMCO's study listed a range of possible reasons behind the mis-pricing trends and noted that most of the reasons were specific to the region and the situation at the time. NEMMCO also commented that the progressive conversion of option 8 constraints to a fully co-optimised formulation would have contributed to the increase in the frequency and duration of mis-pricing.

Subsequent to the publication of the Directions Paper, the Commission requested NEMMCO to extend its analysis in order to develop a more comprehensive picture of intra-regional mis-pricing and its causes. NEMMCO's further analysis looked at three particular questions:

- Has the generalised adoption of fully co-optimised (i.e. option 4) constraint formulation systematically affected the recorded frequency or duration of mis-pricing?
- What is the "positive" and "negative" distribution of mis-pricing (where positive mis-pricing refers to the case where a generator's shadow nodal price is less than the RRP and negative mis-pricing is the reverse)? and
- In what proportions are outage and system normal constraints responsible for mis-pricing?

The further analysis sought to examine the impacts and causes of binding constraints by focussing on five particular areas of the network where congestion is believed to be an issue. NEMMCO's further analysis is released in conjunction with this Draft

Decision Report and is discussed is some detail in Appendix D. The key findings are discussed below.

3.1.3 Distribution of mis-pricing between constrained-off and constrained–on generation connection points

NEMMCO examined the incidence of generators being either constrained-on or constrained-off during the period 2003/04 to 2005/06. In general, a constrained-off generator will be positively mis-priced and a constrained-on generator will be negatively mis-priced.[39] In a positive mis-pricing situation, it is likely that the generator would want to dispatch more output at the RRP but is being constrained-off because of the binding constraint (except where it is already producing at full capacity). In a negative mis-pricing case, the generator may be constrained-on and forced to produce more than it would want at the RRP. The Commission is particularly concerned by this latter situation.

NEMMCO provided data on the following aspects of positive and negative mis-pricing:

- Annual hours of positive and negative mis-pricing per region and generation connection point;

- Number of connection points experiencing either positive or negative mis-pricing per region;

- Annual average magnitude of positive and negative mis-pricing, by region;

- Calculation of the average mis-pricing amount per binding dispatch interval plus standard deviation of that amount; and

- The split average mis-pricing amount per binding interval between system normal and outage, plus the corresponding standard deviations.

NEMMCO calculated the distribution of positive and negative mis-pricing over the period 2003/04 to 2005/06. The results over the three years indicate the following:

- On NEM-wide basis, a generator is significantly more likely to be constrained-off (positively mis-priced) than constrained-on (negatively mis-priced). In 2005/06 the ratio between average hours of constrained-off and constrained-on mis-pricing was 3 to 1; however

- On a region-by-region basis, the frequency of generators being constrained-on and constrained-off varied significantly.

---

[39] Positive mis-pricing occurs when the shadow nodal price is less than the RRP and negative mis-pricing occurs when the shadow nodal price is greater than the RRP. There were a number of other incidences of mis-pricing, relating to equality constraints, which NEMMCO could not classify into negative or positive mis-pricing cases. These equality constraints (i.e. LHS = RHS limit) are unclassifiable because the sign of marginal cost of each constraint is not stored in the NEM solution databases. Equality constraints tend to be applied for operational reasons to control one generator's output (i.e., for non-conformance, system security reasons).

In Victoria, all mis-pricing was positive, with the Latrobe Valley generators always being constrained-off. In the NSW region, most generators were subject to positive mis-pricing, except for Eraring, Munmorah and Vales Point, which were typically constrained-on when being mis-priced. In South Australia, the distribution shifted from generators being predominately constrained-on to being constrained-off. An opposite picture was found for the Snowy Region, with Lower and Upper Tumut changing from being mostly positively mis-priced in 2003/04 to being negatively mis-priced (constrained-on) in the two succeeding years. In Tasmania, both generators that were mis-priced, John Butters and MacIntosh, were generally always constrained-off (i.e. positively mis-priced).

3.1.4 Annual average price impact of positive and negative mis-pricing, by region

NEMMCO also provided data on the average annual price difference between RRPs and shadow prices at generation connection points caused by mis-pricing. The results cover both the average amount for all dispatch intervals and also the average amount for the number of dispatch intervals when the generator was mis-priced. These results require careful interpretation as they would have been influenced by the extent to which generators engaged in disorderly bidding (i.e., bidding in a non-cost-reflective manner to avoid being constrained-on or -off).

The magnitude of the average mis-priced amounts per mis-priced dispatch intervals was very high – ranging around $500 to $1000/MWh for those generators who were subject to positively mis-pricing, and between -$300 and -$6000/MWh for those generators who were negatively mis-priced. These results clearly show there is a high probability of disorderly bidding occurring, when a constraint binds.

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

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

Some market participants stated that the negative effects of pricing mis-match in the NEM may be overstated. The NGF commented that mis-pricing will naturally occur in an "energy-only" market, designed to be over supplied at all times to satisfy system security and reliability standards at times of maximum peak demand. Furthermore, the NGF suggested that the level of inefficient dispatch under most market conditions taking account of the typical level of hedge contracts that participants manage would be less than that indicated by magnitude of price differentials.[40]

While the Commission accepts that a greater level of hedge contracts held by a generator should attenuate its incentives to exploit any market power, the level of hedging is unlikely to prevent generators from bidding in a disorderly manner to avoid being either constrained-on or -off when a constraint binds. In fact, disorderly bidding may occur in order to defend contract positions. New modelling work commissioned for this Report estimates the impact of disorderly bidding caused by mis-pricing on economic efficiency. This work is discussed in section 3.2.1.2

3.1.5 Classification of Congestion between system normal and outage events

The Commission specifically examined information on the classification of historical congestion according to whether it occurred under system normal network conditions or was driven by outage events. This is because, as discussed in Chapter 2, the Commission believes that the appropriate policy response to congestion that arises under different system conditions may well be correspondingly different.

NEMMCO's SOO-ANTS and the AER's constraint impacts reports each provide evidence on the division of congestion arising at system normal times compared to during outage events when outage constraints have been invoked.

NEMMCO's SOO-ANTS split both inter-regional and intra-regional binding hours between system normal and outage events.[41] The data showed that for inter-regional congestion, the incidence of both system normal and outage events increased over the 2003/04 to 2005/06 period of the study. For intra-regional congestion, the frequency of outage events causing constraints to bind increased compared to the incidence of constraints under system normal conditions.

The key NEM-wide results from NEMMCO's analysis were:

- The average hours of mis-pricing due to system normal events were fairly constant at around 50 hours per year over the three years;
- There was an increasing trend in the duration of mis-pricing due to transmission outages, from 20 hours in 2003/04 to over 120 hours in 2005/06;
- In 2005/06, outages events accounted for the majority of average hours in mis-pricing – previously, system normal constraints accounted for the majority of mis-pricing; and
- Most generators were likely to be subject to both system normal and outage-caused constraints.

---

40 National Generators Forum, op.cit. p.16.

41 This analysis was limited in that the classification was based on the current constraint text descriptions and also the possibility that a system normal constraint binding may have been caused by an outage elsewhere on the network.

Further, there was significant variation in the proportion of outage-related to system normal hours of mis-pricing across the NEM regions:

- **NSW** continued to be dominated by outage-caused congestion. The trends in the occurrence of both outage and system normal congestion increased during the period;

- **Queensland** saw a significant increase in outage related congestion and a fall in system normal constraints during 2005/06;

- In the final two years, over 95% of **Victorian** intra-regional congestion was caused by system normal constraints. The overall trend in Victoria was a declining amount of mis-pricing;

- The majority of mis-pricing in **South Australia** was caused by system normal constraints. The trends in the occurrence of both outage and system normal congestion increased during the period;

- **For the Snowy region**, outage events accounted for most of the mis-pricing during the three year period;

- **In Tasmania,** outage events accounted for the bulk of the mis-pricing in 2004/05, but system normal transmission limits were the principal cause of mis-pricing in 2005/06.

The increase in the outage-driven proportion of mis-pricing hours during 2005/06 was mainly caused by outages in the Snowy and Queensland regions. The Queensland increase was influenced by a number of lightening events affecting flows between Central and South Queensland and an outage at the Gladstone transformer.

Meanwhile, the AER's constraint impact reports indicated that an increasingly significant proportion of the total costs of constraints were related to transmission outages.

3.1.6 Factors influencing the extent of congestion and outlook for future trends

As discussed in Chapter 2, 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 market and the interaction of those Rules with the bidding behaviour of participants. Some submissions have advised the Commission that any assessment of materiality should not be based solely upon historical measures of congestion costs but also include also a forward looking appraisal.

The evidence, and the analysis provided by both AER and NEMMCO point to a number of common factors that have a significant influence on the level of congestion in the NEM. These factors affect both the prevalence of system normal and outage-caused binding of constraints. These factors are:

1. Changes to "fully co-optimised" (Option 4) constraint formulation;

2. Transmission Investment;

3. Transmission rating reviews;

4. Network Support Agreements; and

5. Wind farm generation.

The Commission has investigated these factors and have assessed the outlook for the future trend in congestion. This section summaries the assessment and more detail is provided in Appendix D:

- In its additional analysis, NEMMCO found that when option 8 constraints (interconnector-only constraints) were converted to fully co-optimised constraints, the incidence of mis-pricing increased. This factor was a driver behind in the increase in average hours of mis-pricing for South Australia. NEMMCO has now completed the reformulation to fully co-optimised constraints and hence this factor is unlikely to lead to further increases in the recorded duration of mis-pricing;

- Network Support Agreements have been effective at managing congestion in North Queensland and other areas across the NEM;

- The TNSPs have proposed significant investment into the network over the next five years. A review of constraints that have been persistent found that they were either being addressed through planned transmission augmentations or that the associated market benefits were not sufficient to justify the investment.

- The Rules providing the regulatory framework for TNSPs should help to ensure effective and economic management of congestion. This is discussed further in Chapter 7 of the Draft Decision Report.

- The amount of intermittent generation has grown rapidly over the last few years, particularly wind farm development in South Australia. The type of generation can affect NEMMCO's ability to manage the operational of a secure power system and can result in lower transfer capability limits. Evidence suggests that the wind farm development in South Australia has lead to increased binding on the Heywood Interconnector. The Commission is currently considering a Rule change proposal from NEMMCO which addresses these issues related to intermittent generation.[42]

[42] NEMMCO, Semi-Dispatch of Significant Intermittent Generation, Request for Rule Change, 23 April 2007. Available on AEMC website.

This has lead the Commission to consider that the incidence of congestion is unlikely to escalate further in the near future and that there appears to be no location where persistent and material congestion is likely to occur in the foreseeable future increase.

3.1.7 Summary of nature and trends of congestion within each region

From the range of evidence discussed above, the following summary observations can be made about each region in the NEM.

3.1.7.1 Queensland

Intra-regional congestion occurred primarily between the main generator locations (in Central Queensland and the South West) and the main load centres (in Central and South East Queensland). Since January 2002, the Central – North transfer limit has predominately been managed via a network support agreement between Powerlink and generators in northern Queensland.

Congestion has increased over the period, resulting from both network outages and the binding of system normal constraints. A key factor behind this increase has been the strong growth in electricity demand over the period. In 2005/06 there was a huge increase in constraints due to outage conditions. Cyclone Larry affected flows in far North Queensland and lightening and outages at the Gladstone transformer affected flows between Central and South Queensland.

The majority of Queensland generators experienced some mis-pricing each year and were more likely to experience positive mis-pricing and be constrained-off than constrained-on.

There was an increasing incidence of binding on export flows from Queensland to New South Wales. This was due the to inherent transfer capability limit of the interconnector and the system normal capability of the northern NSW network.

3.1.7.2 New South Wales

New South Wales imported a significant share of its generation from the surrounding regions and congestion within NSW affected both intra- and inter-regional flows. A core part of the New South Wales transmission network is a transmission ring that loops around the Sydney and Newcastle areas. Congestion in the network was driven primarily by network outages affecting this ring. Planned outages on the "81" line between Liddell and Newcastle consistently caused a significant share of the congestion in NSW during 2003/04 to 2005/06.

The incidence of mis-pricing in NSW increased due to both outage and system normal events. Most NSW generators experienced some mis-pricing each year, with the significant majority more likely to experience positive mis-pricing and be constrained-off than be constrained-on.

3.1.7.3 Snowy

The Snowy Region has encompassed the key point of persistent and material congestion in the NEM. Outage events accounted for most of the mis-pricing during the three year period. In 2004/05 and 2005/06, generation at Lower and Upper Tumut experienced more negative mis-pricing than positive mis-pricing.

There was significant congestion for flows between Snowy and Victoria, generally driven by system normal constraints. Significant counter-priced flows occurred from Victoria to Snowy over the 2004/05 and 2005/06 summers and led to intervention by NEMMCO, who clamped flows across the interconnector, creating or increasing congestion. The Southern Generators Rule addressed this issue from late 2006.

Congestion also increased between Snowy and NSW due to the inherent limits of the New South Wales network, and also on flows south to Victoria. The increased incidence of binding in 2005/06 on flows south to Victoria was due to higher power transfers into Victoria caused by the drought.

3.1.7.4 Victoria

There was a significant decrease in the incidence of mis-pricing in Victoria over the period. The main congestion points were previously between generation in the Latrobe Valley and load in Melbourne.

Generators in Victoria experienced positive mis-pricing and there was no significant constraining-on or -off of generation between 2003/04 to 2005/06.

There was also a large decrease in the number of hours of binding on exports to NSW via the Snowy Region. However, flows on the Heywood interconnector continued to bind for around 16% of the year. The AER observed that congestion on the Heywood interconnector did not have a significant impact on market dispatch costs.[43]

3.1.7.5 South Australia

South Australia saw a significant increase in the incidence of mis-pricing during 2003/04 to 2005/06. Most of the increase occurred under system normal conditions, although there were a number of significant outage events in the region during the period.

The reformulation of constraint equations to a fully co-optimised form and increased output from wind generation were the primary drivers of the increasing trend. However, the considerable generation capacity at the main load centre in Adelaide combined with a robust transmission network meant that South Australia experienced relatively little intra-regional congestion.

---

43 AER, Indicators of the market impact of transmission congestion, Report for 2005 -2006, February 2007, p.5 and p.29.

3.1.7.6 Tasmania

In Tasmania, a number of smaller generators are distributed across the transmission network with relatively little transmission redundancy. Congestion was primarily driven by planned outages.

3.2 Economic materiality of congestion

The evidence discussed in the section above sets out a detailed picture of prevailing patterns of network congestion in the NEM. The actual or expected occurrence of congestion is a necessary but not sufficient condition for congestion to represent a material economic problem. To assess whether congestion has or will have a material economic impact requires first quantifying the economic costs of congestion and then coming to a view as to whether those costs are material in a policy context.

As explained in the previous chapter, there are a number of routes through which the presence and/or the management of congestion might lead to outcomes that are economically inefficient. In attempting to build a rounded picture of materiality, the Commission has considered evidence on:

- **Productive (or dispatch) efficiency**: To what extent does the presence of congestion add to the cost of meeting demand for electricity in the short term? Congestion might be considered material if less congestion would enable a much cheaper mix of generation to be used to meet demand;

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

- **Dynamic efficiency**: To what extent are investment decisions distorted away from least-cost outcomes by the presence of congestion or by the management of congestion in the NEM? Congestion might be considered material if its presence and/or form of management did not promote efficient long term investment decisions in generation capacity, transmission infrastructure or load.

Materiality in this context needs to be assessed on the basis of whether the costs imposed by congestion are sufficient to warrant changing the Rules. Changes to the Rules impose costs (at a minimum, the costs of practical implementation). Therefore, the evidence on materiality is important in assessing whether change is likely to deliver net benefits to the market. This assessment will vary depending on the nature of the change being contemplated, with more costly changes requiring a higher materiality hurdle.

This section discussed evidence on the economic costs of congestion. Evaluation of the costs of introducing possible congestion pricing mechanisms is provided in Chapter 4.

3.2.1 Productive efficiency

This section considers the evidence on whether congestion significantly increases the cost of meeting demand for electricity by limiting NEMMCO's ability to make use of the least-cost mix of generation. Evidence on this question is published annually by the AER. Further, the Commission has commissioned its own economic modelling on the impact of mis-pricing on the productive efficiency of dispatch. In addition, the Commission has had regard to the economic modelling undertaken in assessing the proposed Rule changes relating to congestion issues specific to the Snowy Region.

3.2.1.1 AER congestion indicators

The AER has published a series of historical indicators of the dispatch costs of congestion for the financial years 2003/04 to 2005/06. For each year, the AER has published data for:

- **The total cost of constraints (TCC).** The TCC estimates the amount by which the cost of supplying load (based on bids and offers submitted) would fall if all transmission constraints were removed. The TCC is calculated by running the NEM dispatch engine (NEMDE) with all network constraints removed, and comparing the dispatch cost under that scenario with the actual dispatch cost;

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

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

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

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

Table 3.1: AER indicators of the market impact of transmission congestion

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

Note: The 2005/06 Figures include any congestion within the Tasmanian transmission network for the first time.

Data source: AER Indicators of the market impact of transmission congestion, Report for 2003/04, 9 June 2006; Report for 2004/05, 10 October 2006, and Report for 2005/06, February 2007.

The AER reported that the number of network constraints significantly affecting interconnector flows increased from 5 in 2003/04 to 32 in 2005/06, while the number of constraints that affected market outcomes within regions on the mainland also increased from 5 to 9 over the same period. Converting the AER's measures into indices with a base year of 2003/04 reveals a near doubling of the TCC and a tripling of the OCC in the three years to 2005/06.

In 2004/05, around $5m of the TCC was attributable to NEMMCO's management of negative settlement residues across the Victoria to Snowy Interconnector. The AER commented that the majority of the TCC occurs over a few days during the year. For 2004/05, 70% of the TCC accumulated on just 7 days. For 2003/04, 60% of the TCC accumulated on just 9 days of the year. In both years, these high costs arose on either the Victoria to Snowy interconnector, the Queensland to New South Wales interconnectors or the lines from the Latrobe Valley to Melbourne.

As noted in the Directions Paper, the AER indicators ought to be interpreted with care, as there are important limitations inherent in the assumptions and methodology.

First, the AER measures relate to the effect of binding constraints on the costs of dispatch as calculated by the NEMDE. These costs of dispatch may diverge from the economic resource cost of dispatch where the industry offer curve (i.e. generator offers) is different to the industry cost curve (i.e. generator resource costs). This may occur due to generators exercising transient market power (bidding above resource costs) or distorting their bids in response to mis-pricing. While it is strictly ambiguous whether these factors, in combination, would lead to the AER measures over-stating or under-stating the economic dispatch costs of congestion, the Commission is concerned that the former result may be more likely. For this reason, the Commission has sought separate modelling that focussed on the resource cost impacts of mis-pricing caused by transmission constraints (see below).

Second, the AER indicators are based on observed generation bids and assume that bids would be unchanged if constraints were removed. However, as explained in Chapter 2 above, both actual and potential congestion can affect generators' bidding incentives and lead them to bid at a price different from their costs. Although the AER tries to remove any distortions to bidding behaviour by replacing the bids of constrained-on generators with a $300/MWh bid, bidding behaviour could nevertheless change if constraints were removed. Furthermore, the AER measures ignore the effects of strategic bidding to prevent or stop constraints binding. If generators bid strategically to stop a constraint from binding, the impact of that potential congestion on efficiency would not be measured. On the other hand, if generators bid strategically to cause a constraint to bind, that constraint would appear more significant than otherwise in the TCC measure.

There are a number of other issues with the AER measure. In order to get a workable calculation of the market impact of congestion, a number of simplifying assumptions were necessary. Some of these assumptions may weaken the ability of the AER methodology to give a comprehensive measure of dispatch inefficiency caused by congestion. Such assumptions include:

- Ignoring any ramp rate constraints for the calculation of non-network constraint dispatch;
- Ignoring any impact of network constraints on the costs of NEMMCO purchasing frequency control ancillary services;
- Exclusion of the cost of load shredding caused by congestion above the Value of lost load ($10,000/MWh); and
- Exclusion of the dispatch costs of generators subject to network support agreements.

Finally, the AER's measures only consider the dispatch costs of congestion and do not provide any indication of the costs of reducing these costs, whether by building out constraints or by pricing more congestion than is currently priced.

Accepting these limitations, the Commission notes that the AER estimates are of a very small magnitude compared to the annual wholesale sales of $6 bn in the NEM. Importantly, the more recent AER reports have indicated that an increasingly significant proportion of the TCCs are related to transmission outages and the majority of the costs occurred on a few days per year.

3.2.1.2 Frontier Economics mis-pricing costs analysis

Following the Dr. Biggar and NEMMCO analysis of the prevalence of mis-pricing in the NEM, the Commission considered that further analysis was required to understand the economic costs of mis-pricing. For this reason, the Commission sought assistance from its Review consultants, Frontier Economics (Frontier), to estimate the production cost impacts of mis-pricing.

Frontier's analysis attempted to calculate the dispatch inefficiency costs caused by generators bidding in a "disorderly"' manner to avoid being either constrained-on or –off in a market experiencing mis-pricing. This analysis was limited to production cost impacts in a price-taking environment – that is, in the absence of any absence of any market power being exercised.. This meant that generators that were not mis-priced were assumed to bid their capacity into the market at their short run marginal cost (SRMC). Meanwhile, generators that were constrained-on were assumed to bid their capacity at $10,000/MWh to avoid being dispatched and generators that were constrained-off were assumed to bid their capacity at -$1,000/MWh to seek to be dispatched.

This approach to modelling behaviour raised a number of issues. First, it assumes that generators can predict whether they are likely to be constrained-on or –off prior to submitting their final offer. Second, it raises the possibility that the disorderly bidding of one generator may cause another generator, which was previously not mis-priced, to be constrained-on or –off. The question then becomes whether the bidding of that first generator ought to be adjusted to reflect its situation. Frontier's approach to addressing this issue was to undertake several iterations of the modelling, allowing generators to diverge from SRMC bidding, until no generator was constrained-on or –off.

Full details of Frontier's methodology and assumptions are contained in Appendix E. A general point worth making is that Frontier did not apply its usual Nash Equilibrium approach to determining market outcomes.

Frontier used the Base case scenario from its most recent model runs for the Snowy region boundary change proposal modelling undertaken for the AEMC. Only the 2007/08 financial year was modelled.

Four modelling iterations under the mis-pricing case were required before no generators were constrained-on or -off. Frontier found production costs in the scenario with mis-pricing across the entire NEM to be $8.01m for the year 2007/08 higher than in the base case in which all plant were assumed to bid their capacity at short run marginal cost. To put this in perspective, actual total production costs across the NEM are greater than $1.7 bn for the year. Therefore, the increase in production costs due to mis-pricing was 0.47%.

At the same time, the assumptions and methodology of the modelling were by necessity highly simplified. The assumptions of price-taking behaviour, the ability of generators to predict their dispatch conditions and the approach for addressing consequential impacts of disorderly bidding on other generators were all made to limit the scope of the analysis.

Finally, it should be emphasised that Frontier's modelling of the costs of mis-pricing had a different focus to the AER's measures of the cost of constraints. Frontier attempted to estimate the welfare costs of mis-pricing alone, not the welfare costs of constraints more generally (which was the AER's focus). In a market with full nodal pricing, in which mis-pricing was eliminated, Frontier's approach would yield a nil cost while the AER's measure may yield a positive TCC figure. Further, Frontier's approach assumes generators' actual marginal costs are the same as the estimates published by ACIL (see above). As noted above, the AER's TCC measure assumes that generators' bids reflect their marginal costs.

The Commission considers the very small amount of dispatch inefficiency estimated by Frontier indicates that the impact of constraint binding on productive efficiency is relatively low.

3.2.1.3 Economic modelling of the congestion in the Snowy Region

The Commission has recently published its Final Determination on Snowy Hydro's Rule change proposal to abolish the Snowy region of the NEM, as well as a number of Draft Determinations regarding various alternative options for addressing congestion in this area. The Commission believes it is worthwhile to recount the results of the dispatch modelling undertaken to support its analysis of those proposals on the basis that the Snowy region has been recognised as a key location of congestion in the NEM.

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

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

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

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

3.2.2 Risk management and contracting

As discussed in Chapter 2, congestion can create a variety of risks for participants to manage. The nature of these risks, and the effectiveness of the tools available for managing them, are important considerations in assessing the economic materiality of congestion. This section considers the evidence on the extent to which congestion poses significant risks to market participants, and whether there are material deficiencies in the available tools for risk management.

Congestion can contribute to price volatility, both within a region as well as with respect to RRP divergences between regions. Such volatility can create financial risks for market participants. The NEM has a high level of price volatility in comparison with other electricity spot markets. This can be due to a number of factors: a) the design of the market, b) volatility of demand, c) transmission constraints and d) generator bidding patterns.[44]

Studies have measured the extent of price volatility in the NEM. Firecone has published figures on the mean and standard deviations of price separation across regions for 2005 (see Table 3.2). This shows that, at times, regional prices separate and the resulting price differences are highly volatile.[45]

Table 3.2: Mean and standard deviation of price separation across regions

	NSW_p-QLD_p	NSW_p-VIC_p	VIC_p-SA_p	$SNOWY_p$-NSW_p	$SNOWY_p$-VIC_p
Mean $/MWh	8.1	4.8	-6.2	-5.3	-0.5
Standard Deviation $/MWh	172.1	264.0	123.6	178.3	156.1

The materiality of financial risks arising from constraints causing inter-regional price volatility is dependent on the effectiveness of the existing risk management instruments available to participants. The Directions Paper presented evidence and market surveys on the effectiveness of the SRA unit as risk management instrument. Since then, the Commission has complemented this evidence base with a series of bilateral meetings with market participants. In discussions with market participants, the Commission found that the risk appetite for trading inter-regional can vary significantly across market participants. Further, participants preferred to use a portfolio of instruments to manage risk and not just rely on one mechanism. Some parties responded that their risk strategy was primarily driven by hedging an 'n-1' plant contingency and that risks caused by congestion were more of a secondary concern. Other parties commented that the difficult in forecasting the timing and impact of network constraints, especially with respect to planned outages, added to their risks.

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

---

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

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

Chapter 5 of this Draft Report discusses the effectiveness of various risk management approaches used by participants in more detail.

3.2.3 Dynamic efficiency

Dynamic efficiency concerns the efficiency of decision-making and market outcomes over time, when network, load and generation infrastructure can change. This section discusses the implications of congestion for these longer-term decisions and outcomes.

As noted in the Directions Paper, the ANTS provides an integrated overview of the current state, and potential future development, of National Transmission Flow Paths (NTFPs)[46] (being the portion of network used to transport significant amounts of electricity between load and generation centres). The ANTS also uses a market simulation model to develop a ten-year forecast of network congestion in order to identify the need for NTFP augmentation from a "market benefit" perspective.[47] In its 2006 ANTS, NEMMCO estimated the present value of the total market benefits of removing all network constraints at $2.2 bn over the next ten years, with markets benefits arising due to lower dispatch costs, deferral of capital expenditure and reliability savings. The Commission remains of the position, expressed in the Directions Paper, that this analysis has limited usefulness in terms of indicating the magnitude of the likely future physical and financial trading risks associated with congestion.

In the Directions Paper, the Commission discussed a report prepared by Intelligent Energy Systems (IES) for the LATIN group, on the potential future dynamic efficiency impacts of more granular congestion and transmission pricing arrangements in Queensland. The Commission has undertaken further work on the issues raised in respect of the IES work and on the detailed methods used in deriving the results. In addition, the Commission has received submissions from both Powerlink and Stanwell that questioned IES's approach and assumptions.[48]

3.2.3.1 Review of the IES report

In its supplementary submission dated 22 December 2006, the LATIN Group presented a report entitled "Modelling of Transmission Pricing and Congestion Management Regime", prepared by Intelligent Energy Systems (IES). This report estimated the extent of dynamic inefficiencies under the current Rules arising through the sub-optimal location and timing of generation and transmission investment, using a case study of a single region in the NEM, Queensland. It

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

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

[48] Powerlink, Response to AEMC Congestion Management Review Directions Paper, 12 April 2007 and Stanwell Corporation, Letter to AEMC on Congestion Management Review, 11 July 2007.

compared the current regime of a single RRP for Queensland and 'shallow' transmission connection charges for generators[49] to two alternative scenarios of: (a) introducing eleven nodal prices for Queensland via a full regime of constraint support pricing (see Chapter 7 for a discussion of CSPs); and (b) including a transmission congestion levy on new generators in additional to the congestion pricing regime included in scenario (a). The IES report found that both hypothetical scenarios would lead to a more efficient pattern of generation and transmission investment in Queensland, with scenario (b) yielding greater efficiencies than scenario (a).

A detailed explanation of IES modelling approach plus a description of the Commission's review is contained in Appendix F. In short, the Commission considers that the following issues place important limitations on the inferences that can be drawn from the IES modelling results:

- No consideration of the risk implications of introducing nodal pricing;
- Modelling was limited to Queensland with simplistic modelling of other NEM regions;
- No sensitivity analysis was performed on results;
- No verification of whether the location of the additional generation was plausible;
- Generic transmission costs estimates were used for congestion levies;
- Transaction costs and implementation costs of introducing new pricing regimes were not included; and
- Simplistic generator entry and reactive transmission investments were used.

The Commission recognises that the dynamic efficiency aspect of congestion could have the largest effect on economic efficiency. Furthermore, with significant investment planned in the energy sector over the next 5 to 15 years, there will be potentially considerable dynamic efficiency effects for the NEM.

However, estimating such effects is extremely difficult. The IES report represents an important and useful attempt at quantifying such effects under various pricing regimes. However, given its limitations, the Commission does not consider that the estimates of the costs of the current regional pricing regime contained in IES report are realistic.

The Commission agrees with the point made in the Stanwell and Powerlink submissions that there are many other important factors besides price signals that influence generation location, and hence, transmission investment. These factors include portfolio risk; carbon risk; fuel source; water source; environmental

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

restrictions (air shed, water, noise, etc). Furthermore the risk management implications of localised nodal pricing would be substantial and need to be reflected in any assessment of different pricing regimes.

The Commission does recognise that that in the future, work will be required to develop a more robust framework for modelling dynamic efficiency impacts, especially for regional boundary assessments.

3.3 Submissions on Materiality

No clear consensus emerged from the submissions about whether congestion is a material problem in the NEM. Some parties stated that the evidence did not suggest that system normal constraints were having a significant adverse effect on dispatch efficiency. Other parties considered that congestion was a material problem and would continue to increase. At the Industry Leaders Strategy Forum held by the Commission, most of the attendees agreed that apart from the Snowy Region, there were no other areas in the network where congestion was a material problem.

There was agreement amongst submissions that the existing indicators on the costs of congestion suggested that congestion was not a material problem, although many submissions also recognised that these indicators do not provide a complete picture.

A number of submissions stated that the Commission needed to balance concern over mis-pricing problem with concern about hedging risks, and recognise the trade-off between dispatch efficiency and contract market liquidity.[50] As noted in section 3.1.4 above, the NGF considered that the problems caused by mis-pricing could be over-stated. It commented that mis-pricing would naturally occur in an “energy-only” market, designed to be over supplied at all times to satisfy system security and reliability standards at times of maximum peak demand. and that the level of inefficient dispatch under most market conditions, taking account of the typical level of hedge contracts that participants manage, would be less than that indicated by the magnitude of price differentials.

Some parties felt that mis-pricing was a natural consequence of the regional market and that this was accepted by the designers of the market.

The Macquarie Generation supplementary submission, which contained a study from McLennan Magasanik Associates (MMA)[51], found that TNSPs were adequately responding to constraints and that there was no material intra-regional congestion. This view was also expressed at the Industry Forum.

---

[50] Snowy Hydro comments that with 80% to 90% of trading volume done by financial contract, the contract market is very important. Its considers that enhancing contract trading through increasing liquidity and availability will increase competition and argues that a decrease in the level of price granularity could be economic efficient if the mis-pricing problem is outweighed by a larger hedging problem.

[51] Macquarie Generation, Supplementary Submission to the Congestion Management Review, 25 September 2006 .

The LATIN Group[52], in its supplementary submission dated the 17 November 2006, put forward its position as to why intra-regional congestion may not be immaterial. The submission disputed the conclusions made in the MMA report, stating that it was not adequate to assess materiality solely on historical measurements or performance of TNSPs because new generation investments would cause more congestion in the future. The LATIN Group noted that TNSPs were prohibited from augmenting the network simply to relieve network constraints unless such augmentation was also required to meet reliability obligations or was shown to be economic (where the value of congestion avoided exceeded the augmentation cost). The LATIN Group recognised that TNSPs' augmentation activities, either on the basis of market benefits or reliability standards, could limit congestion to a certain level. However, they submitted that that level was still likely to be material.

The majority of submissions suggested that the Commission also assess the costs incurred by participants dealing with the uncertainty of congestion and the effect on efficiency caused by potential congestion. Submissions agreed that materiality measures based on actual congestion could understate the problem.

All submissions supported the need to develop the analysis of materiality and stressed the importance of making decisions on changes to the congestion management regime based on the materiality of the problem. Submissions to the Directions Paper agreed that the level of materiality must be determined by the costs of introducing new congestion management mechanisms. Participants considered that a change to the current regime could be justified if the benefits outweighed the costs of the intervention mechanism.

More detail on submissions to the Directions Paper is contained in Appendix A. A summary of earlier submissions to the Review was published as an Appendix to the Directions Paper.[53]

3.4 Commission's observations on materiality

This chapter has discussed the evidence on the occurrence and significance of congestion in the NEM. The Commission has carefully considered the data on the incidence of congestion and the findings on the various studies assessing the economic costs of congestion and considers that the evidence shows that congestion is not a material problem in the NEM. The Commission would make the following observations, which will inform its analysis on options for improving the management of congestion:

- At an aggregated level, the data show an increasing trend in both inter-regional and intra-regional congestion. However, much of this increase, especially in intra-regional congestion, has been due to outage events. Inter-regional

[52] The membership of the LATIN Group has been extended to include Hydro Tasmania and InterGen (Australia) Pty. Ltd.

[53] AEMC, Congestion Management Review, Directions Paper, Appendix A, 12 March 2007.

congestion has also been influenced by the transfer capability limitations of interconnectors;

- Most constraints have a short life-cycle, in that they may cause some economic inefficiency for one or two years before being largely addressed by investment in transmission or generation infrastructure. Consideration of this is required when assessing the various policy responses. There is a danger of implementing medium term mechanisms for what typically tends to be a short term problem;

- On the economic costs of congestion, the available indicators tend to be partial and raise numerous methodological issues. However, the modelling considered by the Commission indicates that there would be limited gains in dispatch costs from addressing either all mis-pricing or even all congestion in the market;

- There do not appear to be many locations in the NEM – outside of the Snowy region and existing regional boundaries – that are likely to experience material and persistent congestion going forward. Hence a localised interim congestion pricing mechanism does not appear to be required at this stage;

- Risk management is an important concern of participants due to the level of spot price volatility and the unpredictable nature of constraints. The Commission agrees with submissions that uncertainty on whether constraints will bind adds to participants trading risks. Improved information on the level of transfer capability and the timing and impact of planned outages will improve certainty for market participants; and

- It is important that the regulatory framework governing transmission services continues to ensures that material constraints are addressed.

This page has been intentionally left blank

4 Pricing

4.1 Introduction

This chapter considers whether changes should be made to the wholesale pricing and settlement arrangements to improve the management of congestion in NEM. The ToR for the CMR highlighted, in particular, the need to examine options that could be introduced on a localised, interim basis prior to congestion being addressed on an enduring basis through regional boundary change or through an investment response from transmission, generation or load.

The manner in which congestion is priced in the wholesale market has an important role to play in managing congestion. As discussed in Chapter 2, congestion can cause the marginal cost of electricity (based on bids and offers submitted) to vary across locations.

Chapter 2 also noted that to the extent these variations in the cost of electricity are reflected in prices, participants will face different types of incentives and risks. Congestion that is reflected in price divergences could potentially provide important economic signals to the market, and positively influence behaviour at both the operational (e.g. generator bidding) and investment (e.g. location and timing) levels.

At the same time, more granular wholesale market pricing to reflect the impact of congestion creates a price or basis risk that participants need to manage. On the other hand, to the extent congestion is not reflected in prices – thereby avoiding basis risk – certain generators may be mis-priced and become subject to volume or dispatch risk (i.e. the risk of being constrained-on or constrained-off). Any change to the balance between priced and unpriced congestion therefore affects the balance of risks that market participants need to manage.

The net effect of any options implementing more granular pricing in the wholesale market depends in part on what financial instruments are available for managing the resultant basis risk and how market participants obtain those instruments. These are important defining characteristics of options for change.

This chapter is organised in a number of sections:

- The first section recounts the locational pricing options considered in the Directions Paper;
- The second section develops a common analytical framework for the purposes of describing and comparing the options for change to how congestion is priced in the NEM;
- The third section uses this analytical framework to compare and contrast a number of specific options for fundamental change that have been raised through the ongoing work on congestion, including through the process of consultation under the CMR;

- The fourth section applies the analytical framework to the option of pricing for constrained-on generation, which is treated as a less fundamental change to the NEM arrangements; and

- The final section sets out the Commission draft findings.

4.2 Congestion pricing options

The Directions Paper outlined a number of incremental and more fundamental reforms that could be made to the pricing of congestion in the NEM. The particular issues raised in the Directions Paper were:

- Pricing for constrained-on generation;

- Limited forms of nodal pricing;

- Constraint Support Contracts and Constraint Support Pricing (CSC/CSP); and

- Constraint-Based Residues (CBR).

In the Directions Paper, the Commission classified most of these options as representing fundamental reforms to the NEM. Nevertheless, the Commission has assessed these options carefully in the light of stakeholders' views, the evidence on the incidence and materiality of congestion (see Chapter 4), and further analytical work to explore in more detail the characteristics and practicalities of different options. The Commission notes that all of these options, and the many variants and hybrids that exist, represent different ways of addressing the same core issues. The Commission has therefore sought to identify a common analytical framework and terminology for explaining and comparing the different options.

4.3 Analytical framework

Chapter 2 introduced the concepts of dispatch and the role of transmission constraints in limiting dispatch to ensure it remains within safe and secure limits. This provides the foundation for understanding the different pricing options available for managing congestion. This section will expand on that foundation by setting out a framework for describing and understanding the different characteristics of, the range of ways in which network congestion can be reflected in how the wholesale market is settled.

4.3.1 Constraint prices

4.3.1.1 For an individual constraint

A constraint which binds imposes a cost on the market. This cost can be measured directly by calculating the reduction in the total cost of the dispatch (based on the bid prices submitted to the dispatch process) that would result if the binding constraint could be marginally relaxed. This can be interpreted as the "price" of the constraint.

When a constraint does not bind, the total dispatch cost will be unaffected by relaxing the constraint limit slightly. Hence, a constraint only has a positive price when it binds.[54] A constraint price is specific to the dispatch interval when it binds. If the same constraint binds in a different dispatch interval, then the constraint price may well be different.

4.3.1.2 For an individual point on the network

Constraint prices can be used to calculate the extent to which a particular point on the network is "mis-priced" relative to its RRN. The concept of mis-pricing and its potential economic consequences were discussed in Chapter 2. If there are no binding constraints, then there will no mis-pricing.[55] If a constraint binds, then locations relating to terms in the binding constraint equation will be mis-priced.

The extent of mis-pricing for any particular connection point on the network, at any particular point in time, will be determined by (a) the constraint price and (b) the coefficient of the corresponding term in the constraint equation. Where a connection point (e.g. the output of a particular generator) is involved in more than one binding constraint, the extent of mis-pricing at that connection point can be determined by adding up the mis-pricing from each binding constraint equation it is involved in and deriving the local nodal price. This difference between the marginal cost of supply at the RRN and the local nodal price at some other connection point in that Region, based on bids and offers, measures the extent of mis-pricing at that connection point.

As noted in Chapter 2, generators are dispatched on the basis of the marginal cost of supply at each individual node, because this ensures that the total cost of the dispatch is minimised. However, each individual generator is settled at the RRP for the output they are dispatched at. Differences between the price at which a generator is (a) dispatched, and (b) settled are the source of the risks of being constrained-on or constrained-off. This, in turn, creates incentives for disorderly bidding, as discussed in Chapter 2.

4.3.2 Constraint rents

A constraint which is binding indicates that transport (transmission) capability is a scarce resource to the market. The value of this scarce resource is equal to the

---

54 More precisely, the constraint "price" reflects the impact on the total dispatch cost from increasing the limit by a small amount. For a constraint which is formulated in the "less than or equal to" form, an increase in the limit relaxes the constraint, resulting in a reduction in the total dispatch cost, and therefore a positive "price". There are a few constraints formulated in the "greater than or equal to" form. For these constraints, an increase in the limit implies a tightening of the constraint and therefore an increase in the total dispatch cost and a negative 'price'. For an "equal to" constraint, an increase in the limit cannot, a priori, be determined to be a relaxation or a tightening of the constraint. For these constraints the constraint "price" has an indeterminate sign.

55 At least if losses are ignored. To be more precise, the NEM uses an approximation to real physical losses within each region in the form of static marginal loss factors. There is at least a theoretical possibility that this approximation will lead to a small amount of mis-pricing compared to full nodal pricing.

volume of energy (in MWs) being constrained multiplied by the constraint price. This can be interpreted as a "rent" earned by the constraint when it binds. A rent is generated every time a constraint binds. How these rents are distributed, either implicitly through the dispatch process or explicitly through the sale or allocation of financial instruments, is a key differentiating features of congestion pricing regimes.

4.3.2.1 Financial instruments derived from congestion rents

The building block of any set of arrangements for reflecting network congestion in prices in the wholesale market are the rents associated with each constraint. Congestion price risk can be characterised as parties being exposed to (i.e. required to fund) these rents when they occur. Financial instruments can be designed to help manage such price risk. The basic approach is to design a financial instrument to enable parties to buy a share in the congestion rents when they occur (and thereby hedge the risk). There are two main approaches to defining such instruments:

- An *unbundled right* to a share of congestion rents for each individual constraint equation involved in the congestion pricing scheme; and
- A *bundled right* to a share of congestion rents across a "bundle" of constraint equations (e.g. all the constraint equations involved in the congestion pricing scheme).

An FTR is a form of *bundled right*, involving the bundle of constraints affecting prices between two nodes. An SRA unit is another example of a bundled right.

4.3.2.2 Methods of distributing congestion rents

A set of congestion pricing arrangements would also need processes to determining how financial instruments derived from congestion rents are to be distributed. There are three main approaches:

- *Auction* the rights;
- *Negotiate* a distribution of rights, and *arbitrate* if no agreement can be reached; or
- *Allocate* the rights in accordance with an administrative rule set when the localised pricing intervention is established.

These approaches relate to congestion pricing arrangements in which rights to congestion rents (or *bundles* of congestion rents) are identified explicitly. There is also the option to allocate rights to congestion rents implicitly through other processes, such as a dispatch process. This is a key feature of the NEM arrangements, and is discussed in more detail below.

4.3.3 Using the description framework to explain different approaches

This section applies the descriptive framework set out above to describe particular approach to congestion pricing, including the NEM and options for reform to the NEM arrangements.

4.3.3.1 Nodal markets

In nodal market designs, there is no difference between the price at which a market participant (e.g. a generator) is dispatched and the price at which it is settled. The settlement price is equal to the marginal cost of supply at each node. There would be minimal risk of being constrained-off or constrained-on, but there would be additional price risk to manage. If a market participant with an exposure to a given connection point wished to contract with any other market participant at a different connection point, that market participant would be subject to an additional risk, often known as 'basis' risk.

Nodal markets generally have (or seek to develop) financial instruments to enable parties to manage this price risk, such as Financial Transmission Rights (FTRs). FTRs are, essentially, a right to a share of the congestion rents resulting from (the bundle of) binding constraints affecting electrical flows between two points on the network – as revealed by a price difference and power flow between the two points. In practice, nodal markets tend to bundle FTRs around the concept of "trading hubs". Market participants are able to buy a portfolio of financial instruments to, in effect, hedge the price risk between trading hubs and from their individual location to their local trading hub.

4.3.3.2 The NEM market design

The NEM market design formalises the concept of a "trading hub" through the definition of RRNs. In many ways, a RRN serves the same purpose as a trading hub. They represent the locations at which financial contracts tend to be written, and are used in structuring financial instruments (i.e. the IRSRs) for managing the price risk of trading between RRNs. However, RRNs are regulatory, rather than commercial, constructs – and consequently require a regulatory process to be followed if they need to change. In contrast, changes to trading hubs in a nodal setting evolve through changes in commercial behaviour. In principle, the commercial route might be expected to be more dynamic and fleixble. However, in practice trading hubs in some nodal markets have proven to be quite resistant to change.

The main difference between the NEM and a nodal market relates, however, to the nature of price risk within a region (or within the scope of a 'trading hub' in a nodal market setting). In a nodal market, individual market participants are responsible for managing the price risk between their location and the local trading hub. In the NEM, this risk is managed automatically for participants through the settlement process. In effect, when a party is dispatched they automatically receive through the regional settlement regime an implicit financial instrument that perfectly hedges the price risk between their location and the RRN for their dispatched volume of output. The precise value of this "implicit FTR" is always the Pseudo Nodal Price multiplied by the actual output.

When the definitions of the pricing regions changes, so does the balance between congestion that is explicitly priced, and the corresponding distribution of implicit financial instruments to hedge price risk within regions. This can be illustrated using the recent Commission determination to abolish the Snowy Region. This change:

- Reduces the number of settlement prices (from six to five);
- Reduces the number of hedging instrument (by abolishing the IRSRs between Victoria and Snowy, and New South Wales and Snowy – and creating new IRSRs between New South Wales and Victoria); and
- Retains the existing method of distributing IRSR units (through the Settlement Residues Auctions) and distributing within-Region "implicit FTRs" (matched to the dispatch) – with Murray now receiving an implicit FTR providing settlement at the Victoria RRP, and Tumut now receiving an implicit FTR providing settlement at the New South Wales RRP.

4.3.4 Characterisation of potential changes to the NEM market design

Section 4.2 above highlighted a number of alternative means of pricing congestion in the NEM that were discussed in the Directions Paper. These include options that might potentially be invoked on a localised, time-limited basis in response to specific congestion issues.

All the options involve a degree of localised spot market pricing in an attempt to overcome the mis-pricing problem that was described in Chapter 2. The key distinguishing feature between the options is the manner in which rights to congestion rentals are "bundled". This section characterises the different options on this basis prior to their assessment.

4.3.4.1 Bundled rights options

There are a number of variants in the class of congestion pricing options which involve bundled rights to the congestion rents. The most obvious, and well-documented example is Constraint Support Pricing/Constraint Support Contracts (CSC/CSP).

CSC/CSP

The CSC/CSP framework has been developed specifically in the context of the NEM, through work undertaken for the MCE by Charles Rivers Associates. The Terms of Reference for the CMR require the Commission to have regard to this work. There are a number of ways of applying the CSC/CSP framework, but the basic model, when applied to give effect to more refined locational pricing for generators, has the following characteristics:

- A set of generators (and interconnectors) and a set of constraints is identified. For example, in the CSC/CSP Trial in the Snowy Region the scope of the pricing intervention was defined in terms of a list of around 130 individual constraint equations representing the flow limit between the Murray and Tumut nodes in the Snowy Region, and encompassed the generators (and interconnectors) involved in those constraint equations (i.e. Upper Tumut , Lower Tumut, Guthega, Murray, Snowy-NSW interconnector, and VIC-Snowy interconnector);[56]

- Each generator involved in the scheme that is exposed to congestion prices is allocated an explicit financial instrument (a CSC) which entitles it to have a specified volume of electricity settled at the relevant RRP (this volume does not change with the identity of the particular constraint that is binding);

- Any generation output over and above the amount specified in the CSC is settled at a price consistent with the congestion prices implied by the constraints involved in the scheme (in effect, an approximation of the exposed generators' local nodal prices);

- The net settlement is therefore a weighted average of the RRP and each exposed generator's nodal price - with the weight of the nodally priced part being determined by the extent to which a generator exceeds its CSC;

- In addition, each interconnector in the scheme is entitled to congestion rents equal to the price difference between the two regions multiplied by a pre-specified volume of its flow (i.e. an explicit CSC volume).[57] These congestion rental payments to (or from) each exposed interconnector modify the net value of the IRSR fund, which comprises the bundle of all constraints that cause price differences between regions. The SRA process is then applied to the modified IRSR fund, with the auctioned products providing firmer hedging than under the status quo; and

- Any congestion rents not explicitly allocated the generators and interconnectors exposed to the congestion prices in the congestion pricing regime would be allocated implicitly to market participants in accordance with dispatch volumes, as occurs under the status quo regional settlements regime.

This option has been developed with the intention of it being applicable to specific setting in the NEM and could be adopted for a limited of time.

LATIN Group proposal[58]

The Latin Group in its response to the CMR Issues Paper, put forward a fully-developed CSC/CSP proposal. The proposal focused, among other things, on the

---

[56] The Snowy CSC/CSP trial was a *partial* implementation of the CSC/CSP concept in that it did not allocate explicit CSCs to one of the interconnector terms involved in the constraints — the VIC-Snowy interconnector. See Appendix E of AEMC 2006, *Management of negative settlement residues in the Snowy region*, Final Rule Determination, 14 September 2006, Sydney.

[57] The interconnector receives an explicit CSC for a defined MW volume in the constraints included in the congestion pricing scheme in which the interconnector is involved and exposed to congestion prices.

[58] LATIN Group, Submission to AEMC Congestion Management Issues Paper, April 2006

difficulties associated with identifying and implementing CSC/CSP on a localised, incremental basis. The solution identified in the proposal was to:

- Apply CSC/CSP across the whole NEM;
- Make a one-off allocation of CSCs (i.e. financial rights to be settled at the RRP) to all existing generators on the basis of a representative dispatch scenario – with CSCs being "non-firm" (i.e. scaled back to match available physical capability) and lasting for the duration of the associated generation asset;
- Make automatic adjustments to the original allocations of CSCs in the event of extra network capacity being made available; and
- Allocate CSCs to interconnector flows, as a means of firming up the IRSR units as a hedging instrument between RRNs and removing negative settlement residues.

This option has been advocated as a permanent change to the arrangements, and would apply NEM-wide.

Other bundled options

There are a number of alternative options which increase the amount of congestion pricing and adopt some other mechanism for re-distributing the associated congestion rents.

To illustrate this range, a highly *bundled* variant could be considered. The congestion rent bundles under this option would be constructed to orient a set of generators to an alternative "pricing hub". The additional hedging instrument sold through auction would be for a share of the congestion rents accruing between the newly formed pricing hub and the RRN. This would have very similar characteristics, from the perspective of generator pricing and management of price risk, to the creation of a new region. However, it would leave the regional pricing of load unaffected. In effect, this option would create an additional "interconnector" (for generators) within an existing region.

4.3.4.2 'Unbundled rights options'

There are another class of options for congestion pricing schemes which seek to "unbundle" the congestion rights implicit in the existing IRSRs or in the CSC/CSP proposal and instead, allocate rights based on each individual constraint equation. One proposal based on this approach is the "Constraint-Based Residues" approach.

Constraint-Based Residues (CBR)

The CBR model specified in Biggar (2006) is an example of an *unbundled* approach – the economic rent (residue) is identified for each constraint equation and placed into its own separate fund. Rights to shares in these funds would then be either allocated or auctioned. Participants would have an opportunity to trade these rights (or to acquire them at an auction) in such a way as to construct the financial hedges there require, such as to construct a point-to-point FTR or to construct separate hedges for particular outage conditions as compared to system normal conditions, etc.

The most general form of CBR set out in Biggar (2006) is not limited to generators. It extends the principle of congestion pricing to all terms in all constraint equations, including load.

4.4 Assessment of fundamental changes

The Commission has assessed the options discussed in the previous section against the MCE's ToR and the NEM objective. The Commission used these criteria to develop an assessment framework based on the following factors:

- Influence on bidding behaviour and dispatch efficiency;
- Practicability and complexity of localised, time-limited application;
- Rights allocation and competition issues;
- Predictability and regulatory risk; and
- Proportionality of response.

The Commission has applied these criteria to the options for fundamental change to the NEM arrangements. Pricing for constrained-on generation is considered in the next section.

4.4.1 Influence on bidding behaviour and dispatch efficiency

4.4.1.1 Addressing mis-pricing

As noted above, all of the pricing options put forward would involve a degree of localised wholesale spot market pricing. This means that the affected generators would be settled at a price that wholly or partly reflected their local nodal price, depending on the number of constraints included in the arrangements and the identity of the constraints that were binding at a given time. The practicability of implementing such options is considered in the next section. However, a key issue for the Commission is whether more "correct" wholesale pricing is likely to enhance or detract from the economic efficiency of dispatch.

In a market characterised by price-taking bidding behaviour, ensuring that settlement prices are consistent with the prices used in the dispatch process ought to promote the economic efficiency of dispatch. This is because participants' marginal decisions would be based on their local nodal price rather than the RRP. As highlighted in Chapter 2, participants (particularly generators) will not have incentives to bid in a disorderly manner (e.g. -$1,000/MWh bids) if dispatch and settlement prices are aligned.

However, where generators have some degree of market power, it is not possible to conclude on the basis of analytical reasoning alone whether more localised pricing arrangements would enhance economic efficiency. This is because generators with some influence over their local nodal price may seek to either withhold a proportion of their output or offer it at a very high (non-cost-reflective) price in order to maximise their profits based on a price-volume trade-off. One manifestation of this behaviour is the tendency of generators to leave some spare capacity or 'headroom' on the transmission network between their location and higher-priced nodes. In the absence of locational pricing, such generators may be incentivised to bid at or below their resource costs in order to be dispatched, and would gain nothing from exercising any transient market power they have.

This issue was highlighted in the Commission's recent analysis of the various Rule change proposals concerning the Snowy region. While one of the options (the Southern Generators' congestion pricing proposal) would have ensured both Murray and Tumut generation received their theoretically correct local nodal prices, the Commission found that this could provide incentives for Snowy Hydro to generate less than in the Snowy region abolition proposal, in which Snowy Hydro had incentives to maximise their volume against the Victorian or NSW RRP for southward or northward flows, respectively.

The presence of a degree of market power means that correcting mis-pricing does not necessarily improve the economic efficiency of dispatch. In such an environment, as was the case in the Snowy boundary situation, the extent to which outcomes are likely to be efficient is an empirical matter.

4.4.1.2 Impacts on hedging

The introduction of localised congestion pricing also affects the ability of market participants to hedge price risk effectively. The introduction of more settlement prices for generators has two effects. First, it reduces the extent to which constraints involving both local generators and interconnector flow terms dilute the firmness of the IRSR units when they bind. Second, it reveals the need for additional hedging instruments for managing trading risks within and across regions.

There are a large number of constraints in the NEM which relate to technical limits on the combined behaviour of generators in a region and interconnectors flows to that region (which in turn reflect the behaviour of generators in other regions). For example, situations where a limited amount of transmission capability is available across a set of generators, some of whom are in a different region. The constraint might bind with low interconnector flow and high regional generator output, or high interconnector flow and low regional generator output. Under the NEM settlement Rules, when the constraint binds at a low interconnector flow, a congestion rent is implicitly transferred from the relevant IRSR fund to the dispatched generators.[59]

---

[59] The converse can apply also, where a constraint is formulated such that a generator can enable more flow on an interconnector by increasing its output. This is the so-called "gate-keeper" generator. There is an implicit transfer of rent from the gate-keeper to the IRSR fund if the gate-keeper increases its output. If the gate-keeper does not have a financial incentive to increase its output (e.g. because it is being settled at the RRP), then the firmness of the IRSR (and the volume of inter-regional hedging available) can be reduced.

This process detracts from the use of IRSRs use as a hedging instrument. Localised congestion pricing, in combination with the distribution of explicit rights to the resultant residues, can increase the firmness of the IRSRs.

Combining the introduction of localised congestion pricing with the introduction of additional financial instruments for hedging congestion price risk offers a theoretical means of increasing the volume of firm hedges available in the market. For example, the introduction of CSCs was seen as an essential complement to the introduction of CSPs because it allows congestion risk to be actively managed via the allocation of CSC. A generator who is allocated a CSC for a volume of output has more certainty over its ability to sell that amount of energy at the RRP, as compared to the current arrangements in the absence of a CSC. This increased sophistication in the range and detail of financial instruments for hedging risk (in this case, the uncertainty over the volume of electricity settled at the prevailing RRP) can enhance market participants' ability to manage risk. This in turn can support higher volumes of contracting within and across regions.

4.4.2 Practicability and complexity of implementation

The MCE's ToR specifies that the Commission must consider the feasibility of a constraint management regime for managing material congestion prior to it being addressed by investment or regional boundary change. This implies that practicability and complexity of implementation are important considerations in determining what types of regime would be appropriate.

A key implementation issue for a congestion management regime is the means of allocating congestion rights. Rights allocation is an extremely vexed subject, to which the next section is devoted. This section is restricted to other implementation questions around a congestion management regime that is required to be both localised and temporary in nature.

The Directions Paper highlighted some of the difficulties with the implementation of a time- and location-limited regime. These difficulties largely relate to the need to resolve a number of matters including:

- The threshold criteria and process for *introducing* a congestion pricing regime;
- The identity of the constraints to be 'priced' as part of the regime; and
- The threshold criteria and process for *removing* a congestion pricing regime, given that it is intended to be a temporary measure only.

While the trial of a CSC/CSP instrument at Tumut (the Snowy Trial[60]) tackled some of these issues, the Commission does not believe that the implementation approach adopted for the Trial is more widely applicable.

[60] In the Snowy Trial, the intent was to enable Snowy Hydro's Tumut generation to be settled at its local nodal price for its marginal output when the Murray/Tumut constraint was binding. When flows through Snowy were in a northward direction, this would increase Tumut's incentive to

While the Commission notes that the Snowy Trial was a positive development for the market, it should also be noted that in a number of ways it represents a special case, possibly unique in the NEM. Specifically:

- The underlying congestion problem was clearly identifiable, well understood, and not liable to change in the short to medium term;

- Only one generation company (Snowy Hydro) and two plants it owned (Lower Tumut and Upper Tumut) that were involved in the selected set of constraints were allocated CSCs. These two generators provide an interconnector support service, which means the flow on the Snowy-NSW interconnector rises above the level it could have in the absence of their generation output. Under the NEM's settlement Rules, in the absence of the trial, the market value of this interconnector support was primarily accruing to the Snowy-NSW IRSR fund (and consequently to Snowy-NSW IRSR unit holders), and not the Tumut generators who were settled at the Murray RRP.

- The trial was a partial implementation of the CSC/CSP concept in that only one of the two interconnectors involved in the constraints included in the trial, Snowy-NSW, was allocated explicit CSCs for a pre-determined volume of its flow (800 MW).[61] The other involved interconnector, VIC-Snowy, was not allocated any pre-defined explicit CSCs, but instead received implicit CSCs equal to its dispatched flow, as per the NEM's standard settlement rules.[62]

- It was relatively straightforward for market participants to agree on an allocation of CSCs between the Snowy-NSW interconnector and Snowy Hydro's Upper and Lower Tumut generation plants because the level of interconnector flow with and without the output of these generators is straightforward to establish.[63]

The analysis undertaken by and for the Commission on the incidence and materiality of congestion clearly demonstrates that, apart from the Snowy area, congestion in system normal conditions has generally been relatively low-level and transitory. This accords with the views of a significant number of stakeholders provided to the Commission at its Industry Leaders Forum on congestion, and more generally through engagement with stakeholders. However, other stakeholders such as the Southern Generators contended the congestion is sufficiently material to warrant addressing through congestion pricing reforms.

generate at times of high NSW prices. When flows through Snowy were in a southward direction, this would reduce Tumut's incentive to generate and consequently reduce the likelihood of counter-price flows.

61 See Clause (m) of Chapter 8A, Part 8 of the Rules.

62 See Appendix E (page E2) of AEMC 2006, *Management of negative settlement residues in the Snowy region*, Final Rule Determination, 14 September 2006, Sydney.

63 Conversely, the non-allocation of explicit CSCs to the VIC-Snowy interconnector in the partial implementation of the CSC/CSP concept meant that there was considerable controversy about the way in which implicit CSCs were allocated to the VIC-Snowy interconnector when NEMMCO intervened in the dispatch process to limit the accumulation of negative residues.

This raises a critical practical issue for application of forms of localised pricing intervention. How is the need for the intervention identified sufficiently far in advance to allow managed and orderly design and implementation, if leading indicators (e.g. historic incidence of congestion) are not reliable? While locations can be identified easily with the benefit of hindsight, it is not at all clear to the Commission that they can be forecast accurately. To illustrate, there is anecdotal evidence from a range of stakeholders that the recent congestion issues involving the South Morang constraint in Victoria were not anticipated.

The one context in which the prospect of a material, but not enduring, congestion problem is likely to be readily identifiable relates to the proposed new process for region change. The Commission published its draft determination and Rule on this issue in September 2007. Under this process, a stage will be reached where the Commission has considered and accepted a proposed region change, with an associated default implementation lead time of 3 years. However, while in these circumstances the congestion problem is clearly identified, it is questionable whether an interim pricing intervention is appropriate. The purpose of the proposed 3-year lead time is to provide market participants with adequate time to adjust to the region change. It is not clear that the implementation of a congestion pricing scheme *in advance of region change* would be consistent with the policy intent behind the 3 year lead time proposal, given that in some ways a congestion pricing scheme such as a CSC/CSP simulates some of the features of region change.

If congestion pricing interventions were adopted in other circumstances, the evidence on the apparently transitory nature of congestion – and the lack of robust leading indicators - suggests two possible risks. First, that instances where greater congestion pricing might improve the efficiency of outcomes are missed. Second, that congestion pricing schemes are introduced where they deliver no benefit.

4.4.3 Allocation of congestion rights

The Commission considers that the allocation of explicit congestion rights is not a matter that is amenable to a simple solution. As noted above, the LATIN Group suggested that CSCs could be allocated to all existing generators on the basis of a representative dispatch scenario. This would have the advantage of ensuring that the timing and location of new investment in generation was based on future expected spot prices at the relevant location, rather than the proponent's expectation of being able to obtain financial settlement at the RRP by bidding in a disorderly manner.

However, the Commission is concerned that allocating explicit congestion rights to incumbents in this way could have two detrimental impacts.

First, the allocation of explicit rights based on historical dispatch would create its own implementation challenges. For example, the choice of the historical period according to which the allocation referred (the 'base' period) would be controversial. Some parties may claim that the period was not representative of more typical periods or that it was not representative of times when the rights would be most valuable. If the base period were to be some time in the future, notice of this fact could distort generator bidding behaviour during that time, as participants compete to secure more of the rights.

Second, it would imply transforming the NEM from a market in which implicit rights to settlement at the RRP are allocated in line with dispatch volumes to a market in which there are explicit rights for incumbents to settlement at the RRP. Since the NEM commenced, all participants have been forced to compete for dispatch on the basis of their bids and offers, and in doing so are assigned implicit rights to settlement at the RRP. While this has led to disorderly bidding at times of constraints and mis-pricing, at least the arrangements have not discriminated in favour of certain participants on the basis of criteria that have nothing to do with their costs. The fact that Chapter 5 of the Rules allows (but does not compel) TNSPs to negotiate with participants regarding compensation for being constrained-on or –off indicates that "access" to the RRP was not to be taken for granted by participants.

An allocation method that provided existing generators with (potentially tradable) explicit rights in preference to prospective new entrants could be potentially viewed as discriminatory and anti-competitive. While this consideration was not relevant in the case of the Snowy Trial, it is a more pressing concern in most other settings in the NEM, where there are number of competing generators potentially affected by the congestion that might be priced through a CSP-type arrangement. This illustrates that the pricing interventions such as CSPs/CSCs can involve significant wealth transfers and represent material changes to the way in which the market operates over time. Consistent with good regulatory practice, such intervention should not be considered lightly and should only be used, in the Commission's view, if they are effective and proportionate to the problem being addressed.

In addition, the above comments assume that the MW volume of explicit congestion rental rights (such as CSCs) would be invariant to the actual output and hence bidding behaviour of the owner. Having an CRR allocation that does not automatically follow dispatch and is also less than a plant's physical capacity (or total load or interconnector capacity), exposes participants to settlement at their local prices, which reflect the market wide externality value of a change in energy injections (or withdrawals) at that location. This can create second order incentives for these exposed participants to be dispatched at the volumes specified by the explicit CRR, in the same way that an energy swap contract creates second order incentives for parties to be dispatched at their contracted volume.

Alternatively, congestion rights may be allocated through an auction process, similar to the existing SRA. While this would avoid many of the issues arising from allocation to incumbents, it would raise a host of other implementation issues. For example, participants are likely to want relatively long-term explicit rights to enable them to hedge financial contracts for several years into the future, whereas at present they automatically receive implicit rights to settlement at the RRP for their entire dispatch volume and these implicit rights exist over the life of the asset (absent any changes to existing Rules). Yet the nature of congestion rights is likely to change over time as constraint equations are altered to reflect transmission augmentation, changes to the provision of NSCS, new generation investment and load growth. Purchasers of explicit congestion rights would be faced with uncertainty over the value of their explicit rights in these circumstances. The Commission recognises that participants currently have to deal with uncertainty over constraint equations and dispatch. However, at least participants have a degree of familiarity with the current arrangements and the Commission's recommendations on improving the transparency and information around constraint formulation and invocation should assist in this regard. The question for the Commission is whether the explicit specification and auctioning of rights will make changes less predictable.

4.4.4 Predictability and regulatory risk

The previous sections have already touched on the different forms of uncertainty that would accompany the implementation of localised and time-limited congestion rights. Each step of the implementation and rights allocation process would be contentious and time-consuming. Changes to the topography of the network or new investments in generation and load infrastructure – possibly even the changes brought about by improved service incentives on TNSPs – could have major effects on the specification and value of transmission congestion rights.

Further, even if implementation of a congestion pricing regime were uncontentious amongst participants, the risk would remain that a regime could be implemented in circumstances where there proves to be no material congestion problem to address. In other words, it is possible that the implementation of a regime would be subject to "regulatory failure". While it could be contended that this risk is relatively small because the additional price risk will be minimal if there is no congestion, an alternative view is that the possibility of inappropriate or poorly focused regulatory interventions in the pricing and settlement arrangements creates an additional form of regulatory risk.

Given that over the next few years, it is likely that a substantial value of new investment is likely to be committed in the NEM, Commission considers the need for predictability in the market pricing and congestion management arrangements to be of paramount importance.

4.4.5 Proportionality of response

The Commission considers that in light of:

- The evidence of limited material congestion in the NEM persisting beyond one or two years at any given location;
- The difficulty of predicting when and for how long congestion will occur;
- The temporary nature of any congestion management regime and the numerous implementation and allocation problems surrounding the provision of congestion rights for parties to hedge the resulting basis risk;
- The scope for investment or regional boundary change to address material and enduring congestion; and

- The ambiguity over whether locational pricing will actually improve the economic efficiency of dispatch in a market where parties have some degree of market power,

the endorsement of a pricing approach to improve congestion management would be a disproportionate response to the problem under examination.

Recommendation 1:

The Commission has reached a draft recommendation that implementing a form of localised spot pricing arrangements based on either:

- **Negotiated allocation of transmission rental rights; or**
- **Auctioned allocation of transmission rental rights,**

would be undesirable for the following reasons:

- **It would be likely to raise significant implementation issues and competition concerns and have significant wealth transfer implications;**
- **It would constitute a disproportionate response to the problems created by the present levels and impacts of congestion, based on currently available evidence; and**
- **Depending on the extent of its application, it could go beyond the scope of the MCE's ToR for the CMR.**

4.4.6 Assessment of pricing for constrained on generation

The Directions Paper highlighted the possibility of changes to the pricing of constrained-on generation as a potential incremental change to the NEM. The prospect of generators being constrained-on was discussed in Chapter 2. In short, a generator is constrained-on if it is dispatched at a level of output above that which it is willing to supply at the prevailing RRP. This can occur because the dispatch process implemented by NEMDE aims to minimise the aggregate costs of serving load based on the marginal cost of supply at each node, while RRPs are calculated as the marginal cost of supply at the RRN. In the presence of congestion, the RRP and marginal cost of supply at different nodes may diverge. For example, a generator that offers to supply at a price of $40/MWh may be dispatched even if the RRP is $30/MWh, if the generator's implied nodal price is $50/MWh. This situation could arise if the generator's output helped relieve a constraint and thereby allowed cheaper generation from elsewhere to supply load at the RRN. Constrained-on generation is therefore a symptom of mis-pricing, which in turn is a feature of a regionally priced market design.

The question raised in the Directions Paper was whether generators that are constrained-on ought to receive some form of compensation to reflect the difference between the price at which they would be willing to supply and the RRP they receive through the settlements process.

The Commission has analysed this issue further in the light of stakeholders' views. Submissions to the Directions Paper expressed a range of views. Some stakeholders supported constrained on payments, and questioned whether the absence of such payments was consistent in principle with an open, competitive market. Other stakeholders expressed concerns about how such arrangements would be funded, and whether it was appropriate for constrained-on payments to be considered in isolation from other means of managing congestion.

4.4.6.1 The current Rules

The Rules provide a framework for constrained on generation. The framework incorporates the following elements:

- Additional payments from NEMMCO for constrained-on generators are not permitted;
- If a generator is constrained-on through a formal direction from NEMMCO, compensation is payable with minimum compensation based on a cost-based formula; and
- Constrained-on payments can also be accommodated in agreements between generators and Network Service Providers, in the context of negotiated access charges under Chapter 5 of the Rules.

Given the existence of this framework in the Rules, the Commission is not persuaded by arguments that there is something fundamentally 'unfair' about constrained-on payment not being more widely applicable in the spot market pricing and settlement arrangements. The case for changing the regime for constrained-on payments must therefore be assessed on the basis of its economic impacts in the context of the NEM objective.

4.4.6.2 Different options for constrained-on payments

Congestion pricing based

Constrained-on payments could be considered as a form of congestion pricing. If a constrained-on generator were 'exposed' to the price of congestion between its location and the RRN, it would be settled at a higher price than the RRP. The *right* to be settled at the RRP for a constrained-on generator is, in effect, a *liability*. This contrasts with a constrained-off generator, who would be settled at a lower price than the RRP if it were exposed to congestion pricing. This illustrates that settlement of the basis of RRPs involves a transfer of economic rents between market participants, such as from constrained-on generators to constrained-off generators.

One option for implementing constrained-on payments is through a congestion pricing scheme of a type discussed in the previous section, such as a CSC/CSP. In practice, it would be a modified, asymmetric form of CSPs/CSCs, which would apply NEM-wide. Generators would only have the *right* to be settled at the RRP for the volume of output they were willing to sell at the RRP. Any output over and above this level would be settled at the CSP, being the local price with the price of all congestion costs relating to the selected constraints included. This would be similar to a pay-as-bid settlement approach for the volume of output being constrained-on.

There are two main issues with this type of arrangement. First, it creates short-term, but potentially very acute, pockets of temporal market power that would have to be dealt with. If a generator knew with certainty (as might be the case under certain outage conditions) that it would be constrained-on, it could set its own price for the amount of constrained-on output.[64] The Commission notes that the transparent abuse of localised market power can be dealt with effectively using contractual or regulatory means — such as minimising (or eliminating) the exposure of a participant with market power to its local price via the allocation of CRRs, and/or by other contractual arrangements. Such approaches are often used in other electricity markets, where localised market power is an issue, and have been used in the NEM in restricting the allocation of IRSR units to Snowy Hydro. The Commission also noted in its Directions Paper that localised abuse of market power that is transparent and exercised over a relatively small customer base should be of much less concern that the masked abuse of market power over a large customer base. In contrast, the abuse of market power in large regions affects a greater number of customers, but is often masked and is therefore more difficult to detect and mitigate.[65],[66]

Second, it would require an external source of funding because it is a one-sided arrangement in which there are not reductions in settlement payments to constrained-off generators. Symmetric forms of congestion pricing, such as CSCs or CBR, involve redistributing congestion rents, such as from constrained-off to constrained-on generators. If the scheme were not to be funded internally, through redistribution, then an external source of funding would be required.

Compensation based

An alternative method of implementing a form of constrained-on payments is a compensation-based approach. This would, in effect, extend the scope of the approach adopted when a generator is constrained-on through NEMMCO direction to encompass all instances where generation is constrained-on. This would address the potential concern relating to the exercise of temporal market power by generators, because the constrained-on payment would not be linked to the value of the bids for the volume of output being constrained on. Rather, the compensation would be based on some sort of formula, that could be based on costs or agreed to in

64 The potential abuse of market power in this way could be mitigated by contracting arrangements.

65 AEMC 2007, Directions Paper, Congestion Management Review, 12 March 2007, Sydney, p.14.

66 Harvey, S.M. and Hogan, W.W. 2000, "Nodal and Zonal Congestion Management and the Exercise of Market Power", Harvard Electricity Policy Group, Cambridge, Mass., 10 January 2000. http://ksghome.harvard.edu/~whogan/zonal_jan10.pdf

a negotiate–arbitrate framework.[67] However, the issue of needing to source external funding for the payments would remain.

4.4.6.3 Economic impacts of constrained-on generation

The Commission has sought to analyse the economic impacts of constrained-on generation in forming a view on whether change to the current framework in the Rules should be changed. The Commission has examined the nature of the problems that might be addressed through the introduction of constrained-on payments, the materiality of those problems and the potential for unintended consequences.

The introduction of constrained-on payments would address one type of mis-pricing that can occur in the NEM. To this extent, it could reduce the incentives that might otherwise apply for constrained-on generators to manage dispatch risk by bidding in a disorderly manner or by understating the physical flexibility of plant for the purposes of dispatch. In doing so, constrained-on payments could overcome one source of dispatch inefficiency and these generators would have one less risk to manage in making investment and operational decisions.

However, the expense of making constrained-on payments to generators would need to be funded by some external party. If the funding for a constrained-on payment scheme were met through a market levy (e.g. in a similar way to the recovery of NEMMCO costs), the expense would be incurred by the generality of customers, in the absence of clearer method for allocating costs. If the cost were recovered through transmission charges, then in effect the costs would be recovered from load in the relevant transmission areas that benefited from constraining on the generation. This form of recovery would be on a more geographically specific basis than a market-wide levy).

There could be, however, unintended consequences from the introduction of a constrained-on payments scheme. These relate the scope for, and exercise of, transitory market power by constrained-on generators. This could impact on the cost of funding the scheme over time. Further, in practice, the incidence of constrained-on generation is closely linked to the incidence of constrained-off generation. This is most evident where there is congestion on a transmission loop. In these circumstances, it might potentially be profit-maximising for a portfolio of generation to enter a combination of bids to contrive a situation of being constrained-on for one of its plant – in order to reap the price benefits of being constrained-off for some of its other plant. A regime of constrained-on payments in this context could simply increase the profits from bidding in a non-cost-reflective manner.

A final economic impact of a constrained-on payments regime is the interaction between transmission and generation. One interpretation of constrained-on generation is that it provides support to the transmission network. The reason such generators are being required to run is a shortage of network capability. The Rules recognise this interaction and provide for contractual relationships between

[67] The existing Rules contain provisions for formula based compensation for participants who are directed by NEMMCO — see Clauses 3.15.7, 3.15.7A, and 3.15.B. The funding of these compensation payments is via a levy on Market Customers applied in accordance with Clause 3.15.8.

generators and TNSPs to be made under the provisions in Chapter 5. These could take the form of network support agreements. Imposing a constrained-on payments regime through the pricing and settlement arrangements might be viewed as pre-empting a transmission response. However, it might also be argued that a formalised constrained-on payment regime would give greater visibility to the absence of transmission responses, such as through contract or through investment, and might represent an additional discipline on TNSPs under a service incentive framework.

4.4.6.4 Materiality of constraining-on

The Commission's general approach to the CMR has been to assess potential changes to the existing arrangements in the light of the evidence on the materiality of the problem being addressed by the change.

The evidence on materiality of congestion was discussed in detail in Chapter 4 above. The key observations in respect of constrained-on generation are as follows:

- For the three years from 2002/03 to 2005/06, there were on average around 40 connection points in the NEM that were constrained-on. This is about half the number of connection points that had been constrained-off;

- Constrained-off generation was generally affected for a greater number of hours than constrained-on generation; and

- There was no constrained-on generation in Victoria, and constrained-on generation was limited to Eraring and Vales Point in NSW.

This evidence, in combination with the absence of stakeholder submissions highlighting constrained-on risk as a significant issue, does not in the Commission's view provide strong support for change. This view is supported further by the lack of evidence to demonstrate that existing mechanisms for contractual arrangements between generators and TNSPs are not working effectively. Conversely, the Commission is aware of some examples where contractual arrangements are being used in the context of network support.

Recommendation 2:

The Commission has reached a draft recommendation that implementing a regime of constrained-on payments through changes to the Rules to settlement of the spot market would <u>not</u> represent a proportionate means of improving the management of physical and financial trading risk from network congestion.

5 Risk management

5.1 Introduction

This chapter considers financial risk management in the NEM, and recommends a number of improvements to the existing SRA mechanism and the way negative settlement residues are managed as a means of reducing inter-regional trading risk.

The ToR for the CMR requires the Commission to identify and develop improved arrangements for managing financial and physical trading risks associated with congestion. As noted in Chapter 2 above and the Commission's Directions Paper, congestion can give rise to both physical (dispatch) and financial (basis) trading risks.

As noted in section 2.3.2.1, there may be a trade-off between a market design that seeks to overcome dispatch risk (through *more* granular settlement pricing arrangements to avoid mis-pricing) and a market design that seeks to overcome basis risk (through *less* granular settlement pricing arrangements). This suggests that attempts to address the mis-pricing problem by providing more pricing nodes must concurrently offer adequate hedging options to enable participants to manage the resulting basis risk. Because basis risk is only a concern to the extent that adequate hedging instruments are not accessible, one way to describe the implications of basis risk is that it can give rise to a "hedging problem". IRSR units available through SRAs are the key mechanism within the NEM design that seeks to provide a hedging instrument to address this basis risk.

Having come to the view in Chapter 4 that the introduction of more localised pricing arrangements was not warranted at present, this chapter deals with potential options for improving the way the existing NEM design deals with the hedging problem.

5.2 Tools currently available to address the hedging problem

5.2.1 IRSR units

As noted in Chapter 2, IRSR units are one of the key tools for assisting participants to manage basis risk in the NEM. Chapter 4 explained that IRSR units are a form of FTR, which are auctioned in advance through quarterly SRAs. Broadly speaking, the IRSR units associated with a particular "directional interconnector" provide the holder with a share of the positive stream of payments or "residues", equal to the price difference between the two regions joined by the interconnector (in the direction of the directional interconnector) multiplied by the flow on the interconnector (when the flow is in the direction of the directional interconnector). Each IRSR unit refers to a notional 1MW of the nominal flow limit of the corresponding directional interconnector. For example, if the nominal flow limit on an interconnector is 1000MW, 1000 IRSR units would be auctioned and the holder of ten IRSR units would receive a flow of payments equal to one percent of the residues described above.

IRSR units would provide a reliable hedge against inter-regional price differences if a party wishing to trade between two regions could predict with certainty the flow capability on the directional interconnector when there was a price difference between the regions. The volume of reliable hedging residue available would depend on the interconnector flow when there was a price difference. For example, if the flow capability at times of price separation was known to be always 1000MW, trading parties could contract across the region boundary up to this limit and remove any basis risk through the purchase of IRSR units. This known volume might or might not be equal to the nominal interconnector limits used to determine how many IRSR units were sold.

However, in practice, the level of flow capability on directional interconnectors at times of price separation is not known with certainty for a number of reasons including:

- The physical limits of the transmission assets that comprise an interconnector might be temporarily below their normal operating levels due to, for example, maintenance work or weather conditions;

- The flow on a directional interconnector might jointly depend on the output of particular individual generators who make use of the same parts of network – they are, in effect, competing over a limited amount of capacity. When price separation occurs, the level of interconnector flow would depend on the output of these generators (which in turn depends on generator bidding behaviour); and

- The relationship between flows on an interconnector, the output of other proximate generators, and constraints on available capacity may be such that the interconnector flows "the wrong way", (i.e. counter-price, from the higher priced to the lower priced region).

If any of these outcomes occur, the IRSRs accruing in respect of an IRSR unit will not be a firm hedge for an equivalent 1MW inter-regional contract exposure. In practice, all of these outcomes occur periodically. This is perhaps not surprising when it is recognised that a significant proportion of potential network constraints involve interactions between interconnector flows and the output of individual generators. To predict what interconnector flows will be when these types of constraint bind and drive price separation requires individual trading parties to be able to accurately predict what the output (and hence bidding behaviour) of potentially multiple individual generators. This is a very difficult task, and therefore contributes to the lack of firmness of IRSR units.

The possibility of negative settlement residues accruing creates an additional source of reduced firmness of IRSRs. The current Rules stipulate that for each directional interconnector, positive residues can be used (within the same billing week) to net off any negative residues that might occur as a result of counter price flows. Other things being equal, this will reduce the funds paid out to IRSR holders and therefore reduce the firmness of the hedge. The magnitude of this effect is limited by NEMMCO's current practice of clamping interconnector flows if there is the prospect of negative residues accumulating to a value greater than $6,000. However while clamping firms the IRSRs in the counter-priced direction by reducing negative residues, it makes no contribution to firmness of the IRSR in the positive-priced direction (i.e. from the low priced region to high priced region) because when clamped to zero flow, no positive residues can accumulate in the IRSR fund.

The management and funding of negative settlement residues is discussed in more detail in section 5.3.2 below.

5.2.2 Other tools

Participants also make use of financial contracts such as capacity swaps to manage inter-regional risk. This review has not considered the specific financial contracts available for managing inter-regional risk, as the Commission believes the design of financial contracts is best left to participants in financial markets. However the Commission does consider the liquidity of financial markets in all its decisions, and notes that participants generally consider financial market liquidity to be adequate in all regions but South Australia.[68]

5.3 IRSR unit firmness

This section considers the firmness, or reliability, of IRSR units as a hedging instrument, and makes recommendations for improving IRSR firmness.

Following the publication of the Directions Paper, the Commission considered stakeholder submissions on risk management issues in the NEM and engaged in several bilateral discussions with stakeholders in order to better understand their views on whether and how risk management tools could be improved.

Many participants criticised the existing IRSR instrument for lacking firmness. Snowy Hydro said that IRSR units were imperfect and only supported incremental inter-regional trading (as supported by the Anderson, Hu and Winchester survey). MEU agreed that IRSR units were an ineffectual risk management instrument but raised concerns that fully firm instruments (such as firm FTRs) could lead to higher costs for consumers. NEMMCO agreed that IRSR units could be made firmer by funding negative settlement residues in some way, perhaps based on the FTR model. The NGF also supported changes to the SRAs that could “firm-up” IRSR units. In particular, the NGF advocated recovering all negative settlement residues from auction proceeds, in place of the current Rules netting negative residues off against positive residues within each settlement week. The Southern Generators agreed that the current arrangement ought to be changed.

As noted above, it is clear that the lack of firmness provided by IRSR units might be expected to detract from parties’ willingness to trade inter-regionally and hence from the liquidity of contract markets, in terms of volumes of contracts and numbers of contracting parties. While it would be very difficult to quantify the impacts of increasing IRSR firmness on inter-regional trade, it seems reasonable to infer that

68 PriceWaterhouseCoopers, New Perspectives on Liquidity in the Financial Contracts Electricity Markets, Survey November 2006.

improvements to the effectiveness of the hedging instruments would lead to greater inter-regional trading.

Against this background, the Commission considers that there are three broad approaches to firming-up IRSR units:

- Improving the reliability and predictability of the underlying network;
- Amending the arrangements for managing and funding negative settlement residues; and/or
- Using a source of external funds to increase payments to IRSR unit holders.

Each of these options is discussed below.

5.3.1 Improve the reliability and predictability of the underlying network

The need for instruments to manage basis risk from trading across regions reflects the possibility that prices between regions will separate. This occurs primarily as a result of network constraints binding. The likelihood of network constraints binding is, in turn, influenced by the transfer capability of the underlying physical transmission assets – and how those assets are operated at any given time.

Improving the reliability and predictability of the transmission capability derived from the underlying physical network and how it is operated is an important factor in firming-up IRSR units. If interconnector transfer limits could be accurately predicted by participants, purchasers of IRSR units could determine the required number of IRSR units required to hedge a position with a high degree of certainty.

The Commission considers that many improvements have recently been implemented or are in the process of being implemented that should improve the reliability and predictability of interconnector transfer capability. These include the Chapter 6 Transmission Revenue and Pricing Review, the Last Resort Planning Power, the MCE Region Boundary Change Criteria and Process and the Rule Determination on the Snowy Region Boundary.

The AER is currently developing incentives for TNSPs that relate directly to increasing the provision of transmission capability at times when it has most value to the market, i.e. when constraints are binding. This work is focused on improving the incentives for TNSPs in how they manage and schedule network outages. The importance of this work is supported by the Commission's findings in Chapter 3 that the incidence of outages causing constraints is increasing. The Commission expects this work, when implemented, will make a strong positive contribution to the firmness of IRSRs.

There are also prospective measures that might influence the provision of inter-regional transfer capability, and by extension the firmness of IRSR units. The most significant of these measures is the direction provided to the AEMC by the MCE to develop a framework for a National Transmission Planner. The Commission published a Scoping Paper[69] on the National Transmission Planner in July 2007 and is scheduled to publish an Issues Paper in October 2007.

This package of recent and ongoing reforms, combined with other recommendations in Chapter 6 of this report regarding the management of constraints, are likely to significantly improve the reliability and predictability of interconnector transfer limits. The Commission believes that the current reforms must be allowed to take effect before further reforms to improve the reliability and predictability of interconnector transfer limits are contemplated.

5.3.2 Management and funding of negative settlement residues

5.3.2.1 Why negative residues occur

The prospect that constraints may bind such that there is (a) price separation, and (b) a flow on a directional interconnector in a counter-price direction is a potential factor reducing the firmness of the IRSR units. There are two separate effects at work. First, at times of counter-price flows, positive residues are not accumulating on the directional interconnector from the lower to the higher priced region. Second, positive residues that would otherwise be payable to holders of units in the directional interconnector going the other way, may be used to fund the negative residues (in the same billing week). Hence, the IRSR units may be made less firm in both directions of an interconnector by a single incident of negative residues accumulating.

The Commission notes that there are a number of potential reasons why a dispatch might result in an interconnector flowing in a counter-price direction:

- Islanding – where a part of the network is physically separated from the rest of the network so that power cannot flow between the two and a counter-price flow is required to support a load in a separate region within the "island". In this case, a counter-price flow is likely to be efficient, because the alternative would be load-shedding and a potential exacerbation of the islanding problem;

- Network loops – where a network loop exists that crosses a region boundary such that, by definition, flows along one section of the loop will be in the "right" direction and flows along another section of the loop will be counter-price. The abolition of the Snowy region, which takes effect on 1 July 2008, will remove the most significant inter-regional loop in the NEM;

- Interaction between a DC and AC interconnectors crossing the same region boundary;

- FCAS constraints – optimising energy and FCAS can result in a counter-price flow, but is likely to be of limited materiality;

[69] AEMC, National Transmission Planner, National Transmission Planning Arrangements: Scoping Paper, August 2007.

- "Disorderly" bidding – where a single constraint involves an interconnector flow and a number of individual generators and those generators are dislocated from the setting of their RRP but are seeking to maximise output at the prevailing regional price. In these circumstance, the generators may bid in a disorderly way (e.g. -$1,000/MWh), which in turn might be sufficient to back-off the interconnector flow to such an extent that it flows in a counter-price direction; and

- The 5/30 Issue – Rapid changes to power flows within a 30-minute trading interval.

5.3.2.2 The funding of negative residues

How the prospect and incidence of negative settlement residues is managed can influence the firmness of IRSR units. The current arrangements, in addition to limiting the incidence of negative settlement residues by allowing NEMMCO to intervene in the physical dispatch (clamping), fund any residual negative residues in two ways:

- If there are positive residues on the same directional interconnector in the same billing week as the negative residues, the positive residues are used to net-off the negative residues; and

- Any remaining negative residues after netting-off within the billing week are funded from the proceeds from the next auction(s) for that directional interconnector.

When the Commission made the Rule[70] on 30 March 2006 enabling negative residues to be funded from auction proceeds, a three year sunset was included to clearly signal its view that this was not considered to be a long-term response to the negative settlement residue issue. The Commission's intention has always been to examine the range of issues involved more thoroughly in the context of the CMR.

The Commission's analysis of netting-off from the same directional interconnector fund suggests that netting-off within a billing week is in many ways equivalent to recovery via auction fees. In effect, a negative residue netted-off within a billing week represents an additional *ex post* "fee" (equal to the positive settlement residues foregone) borne by the purchasers of IRSR units.

The difference between netting-off and explicit recovery from auction fees is that the latter approach recovers the shortfall from future auction fees, while netting-off effectively increases the auction fee paid by the current holders of IRSR units. Allowing negative settlement residues to reduce the value of currently-held IRSR units would tend, other things being equal, to reduce the value of IRSR units for hedging purposes. This would presumably be reflected in the prices participants were willing to pay for IRSR units in the SRAs. Given that the "importing" TNSPs'

---

[70] AEMC 2006, National Electricity Amendment (Negative Inter-Regional Settlements Residue) Rule 2006, Rule Determination, 30 March 2006, Sydney.

load customers are ultimately the beneficiaries of both SRA fees and proceeds through lower transmission use of system (TUoS) charges than would otherwise be the case, they would therefore ultimately incur the cost of funding negative residues irrespective of which of the two ways this occurred.

The appropriateness of the entitlement of an importing region's customers to SRA proceeds is a matter that was touched on but not addressed in the Commission's review of transmission pricing arrangements in 2006.[71] The Commission considered that this was a matter upon which jurisdictional advice was necessary. However, it may not be unreasonable for negative settlement residues to be recovered from the importing region's TNSP in any case. This is because loads in an importing region would also have benefited from the counter-price flow that led to the negative settlement residues in the first place, in that the counter-priced flows may have led to a lower RRP in the importing region than would otherwise have been the case. This provides an equity-based argument for retaining the current focussed approach to recovering (net) negative settlement residues from the importing TNSP alone.

In this context, an alternative to recovering negative settlement residues from SRA proceeds may be for NEMMCO to charge the importing region's TNSP directly for any negative settlement residues. This could improve the transparency and clarity of the recovery process. The Commission also notes that, from a practical perspective, a mechanism already exists under the Rules for NEMMCO to charge negative residues to a TNSP (which it is understood related to instances when IRSR units are unsold). The Commission seeks the views of stakeholders on these options, in particular from TNSPs in respect of whether this raises any issues for its price-setting and revenue recovery procedures under Chapter 6A of the Rules. Transitionary arrangements may be required to ensure TNSPs are capable of passing on negative residues to customers and are not left bearing the cost themselves.

Recommendation 3:

- **That negative settlement residues no longer be netted-off against positive residues within a billing week; and**
- **That negative residues be funded by directly billing the importing region's TNSP.**

5.3.2.3 Managing negative settlement residues by zero flow clamping

Part 8 of Chapter 8A of the Rules currently permits NEMMCO to use "alternative constraint formulations" to prevent material negative residues from arising. In practice, this results in NEMMCO constraining interconnector flows (clamping) through the dispatch process to prevent negative residues accruing beyond the $6,000 threshold set out in its published operating procedure.[72] Clamping was only

[71] AEMC 2006, National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22, Rule Determination, 21 December 2006, Sydney.

[72] NEMMCO, Operating Procedure: Dispatch, 16 March 2007, www.nemmco.com.au.

ever intended to be an interim solution to managing negative settlement residues until a more acceptable solution was developed. Hence the clamping provision was included in the Rules as a derogation. In May 2007, the Commission decided to extend this derogation from 31 July 2007 to 31 October 2008.

In general terms, the Commission believes that physical interventions such as clamping are inherently problematic, and if possible, should be avoided. Although NEMMCO follows published procedures when invoking clamping, in practice it is extremely difficult for participants to predict when clamping will take effect, how quickly it will proceed and how it will impact dispatch and pricing. This creates risks for participants that are difficult to manage and the cost of this uncertainty is likely to be built into contract prices and filters through to higher energy costs for customers. Also by definition, clamping moves the market away from least-cost dispatch, which would reduce economic efficiency assuming bids and offers were cost-reflective.

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

In light of these factors, the Commission believes that while clamping is a far from ideal response to counter-price flows, removing clamping altogether could greatly distort generators' bidding incentives (i.e. by encouraging disorderly bidding) and undermine the value of IRSR units as hedging tools. A compromise approach could be to increase the threshold for clamping to be implemented. In 2006, NEMMCO consulted on lifting the clamping threshold from $6,000 to $100,000.[73] None of the six submissions to this consultation supported the proposal. The main reason cited for this was that a higher clamping threshold would reduce the firmness of the IRSR units due to the netting of negative residues against positive residues during the billing cycle. The Commission is recommending (see above) that the practice of funding negative residues by netting off within the billing week should cease.

The other concern raised in three of the submissions to NEMMCO's clamping threshold consultation regarded a concern that lifting the clamping threshold would permit a longer duration of inefficient dispatch. The basis for this view is that where negative residues reflect disorderly bidding, by definition the market is being dispatched on the basis of bids that do not reflect costs. The Commission has taken this concern into account in outlining the option of "positive flow clamping" in certain circumstances (see below).

In this context, the Commission proposes to increase the clamping threshold to $100,000. This view is based on the following:

73 NEMMCO, Review of Trigger Level for Management of Negative Settlement Residue, Final Determination Report, 27 October 2006, www.nemmco.com.au.

- Intervention through clamping creates uncertainty for participants which flow through to customers as higher energy prices;

- In some cases, inefficient dispatch will be prolonged as a result of lifting the threshold, but equally in some cases efficient dispatch will be allowed to run longer as result of delayed clamping. The option of positive flow clamping (see below) could assist in limiting inefficient dispatch in many cases;

- NEMMCO has indicated that they are able to manage the negative settlement residue liability based on a $100,000 clamping threshold; and

- There will be no impact on firmness of the IRSR units if this is progressed in parallel with the Commission's recommendation above that negative settlement residues should be charged to the relevant TNSPs, rather than recovered auction fees or proceeds.

The Commission considers this to represent an incremental improvement in the intervention regime, which will in time generate further information on this vexed issue. The need for physical intervention as a means of managing negative settlement residues, and the level of the threshold for invoking such an intervention should be reassessed after three years experience with these changes in place with a view to complete removal if possible.

The Commission also believes that it would be worthwhile to ensure that NEMMCO's application of its clamping procedure is as transparent and predictable as possible. NEMMCO should be obliged to outline how it interprets and applies those provisions of the Rules that enable it to effect clamping in the constraint guidelines recommended in Chapter 6.

Recommendation 4:

- **That the threshold at which NEMMCO intervenes to limit the accumulation of negative settlement residue be lifted from $6,000 to $100,000;**

- **That the need for physical intervention as a means of managing negative settlement residues, and the level of the threshold for invoking such an intervention should be reassessed in three years with a view to complete removal if possible; and**

- **That NEMMCO should be obliged to outline how it interprets and applies those provisions of the Rules that enable it to effect clamping in the constraint guidelines recommended in Chapter 6.**

5.3.2.4 Managing negative settlement residues by Positive Flow Clamping

This section considers Positive Flow Clamping (PFC) as an alternative to zero flow clamping to manage negative settlement residues. PFC works by clamping the relevant interconnector to a positive flow (in the direction of the lower priced region to the higher priced region), rather than clamping to zero flow as is the practice under zero flow clamping. The main benefit of PFC compared with conventional clamping is that positive IRSRs continue to accumulate following the intervention, thus improving the firmness of IRSR units. As measures that reduce the trading risks of congestion is a key element of the CMR, the Commission considers it important to fully consider the PFC option.

The concept of PFC was raised in a generic manner in the Directions Paper, as an option that would confer priority to interconnector flows in the event of a constraint that limited both intra- and inter-regional flows. Both Macquarie Generation and Snowy Hydro supported this option. Macquarie Generation said that it would be possible to implement a discretionary constraint to fully restore interconnector flow and ensure positive residues where pre-dispatch was showing likely counter-price flows caused by disorderly bidding behaviour. Another alternative would be to provide for a sharing of the available transmission capacity between "local remote" generation and interconnector flows based on some form of pro-rating. Macquarie Generation also considered that either a full interconnector priority option or some kind of a sharing approach would provide a sharper locational signal for new generation investment. Snowy Hydro advocated the same proposal as an alternative to a CSC/CSP or CBR approach to managing congestion. Snowy Hydro saw the advantages of such an approach as lying in eliminating negative settlement residues (without clamping) and maximising the usefulness of IRSR units for inter-regional trading.

NEMMCO expressed support for less complex and uncertain alternatives to clamping, but had several concerns with clamping the interconnector to a positive value, including: (1) a possible conflict with the MCE position to use "fully optimised constraint formulation"; (2) the option could increase the economic cost of dispatch; and (3) that a number of practical implementation issues would require resolution.

The Commission wishes to explore the potential benefits (and implementation issues) of the PFC option further and has specified the following high level design to facilitate a targeted response from stakeholders:

- PFC will be considered only for counter-priced flow events that are caused by generators' incentives to bid below avoidable cost due to constraints binding that create a disjuncture between dispatch and settlement at the RRP. Such events would be pre-defined and identified by constraint equations;

- PFC would be invoked when negative residue caused by one of the defined constraints were forecast to accumulate to $6000;

- Under PFC, the interconnector would be clamped to the flow at which that interconnector was dispatched in the dispatch interval just prior to the PFC invocation, if that flow was in the direction of lower priced region to higher priced region; and

- If the interconnector turns counter-price or was already flowing counter-priced prior to PFC being invoked, the default arrangements for managing counter-priced flow (i.e. clamping to zero MW) would apply.

The Commission makes the following initial observations of the impact of PFC. A more detailed explanation of the proposed PFC design together with the reasoning behind that design can be found in Appendix G.

Effect on IRSR firmness

PFC would improve the firmness of IRSR units in the circumstances in which it applied in place of conventional zero flow clamping. This is because under PFC, the interconnector would be constrained at a non-zero level in the positively priced direction, which would result in the accumulation of IRSRs, whereas under the current clamping regime, no IRSRs accumulate.

Firming-up IRSR units would encourage more participants to use this product to hedge basis risk (as opposed to using the IRSR product for speculative purposes). This could promote inter-regional contract trading, although it is difficult to assess the likely magnitude of this impact. IRSR units would still not be fully-firm and the returns would still be unpredictable due to unreliability in the underlying network. The question is thus by how much PFC would improve firmness and to what extent would it enhance inter-regional trade.

Effect on dispatch

PFC would result in a different dispatch outcome to the current clamping regime. Intra-regional generators[74] would be backed off to a greater extent, while inter-regional generators would be allowed to generate more.

In the presence of transient market power, it is, strictly speaking, not possible to determine the dispatch efficiency effects of PFC based on dispatch bids and offers alone. However, in a price-taking environment, it could be argued that PFC would often improve dispatch efficiency. This is based on the presumption that dispatch was efficient before the conditions for disorderly bidding and counter-priced flow were established. If this is the case, then PFC would maintain dispatch broadly in line with that efficient outcome, whereas clamping to zero MW or allowing the negative residue to accrue from a counter priced flow would both result in a move away from efficient dispatch.

System security

PFC and clamping both involve NEMMCO retaining the same level of control over the same variables in the dispatch. Hence, both would appear consistent with the secure operation of the power system. Neither intervention would be invoked if to do so would compromise system security. PFC and clamping would be discretionary interventions for NEMMCO to apply under the Rules (subject to consultation, publication and compliance with appropriate guidelines).

[74] Those generators with coefficients in the relevant binding constraint equation.

Constraining-on interconnectors has the potential to result in generators in the importing region being dispatched below technical limits. However this is considered unlikely because dispatch would not be expected to vary significantly under the approach described above.

Dynamic efficiency effects

Placing further constraints on the intra-regional generation contributing to congestion may enhance incentives to manage that congestion in the following ways:

- Incentives for efficient decisions by new generation not to locate in 'remote' locations within a region (those locations where generation would place pressure on the constraint), or potentially for existing generation to de-commission in such locations; and

- Incentivises affected generators to find innovative ways, possibly in conjunction with TNSPs, to reduce the frequency and duration of constraints leading to negative settlement residues.

Financial market competition and liquidity

The likely effect of PFC on financial market liquidity is unclear. As described below, PFC may: (1) result in a greater number of contract providers within a region, and (2) result in a change in the volume of contracts offered:

- Firmer IRSR units should encourage generators from other regions to offer a greater volume of contracts to counter-parties in the region experiencing constraints. This would result in greater competitive pressure on contract prices; and

- Intra-regional generators that are constrained-off by PFC will face additional dispatch risk, because at times when PFC is invoked, their access to the RRN would be reduced by the level at which the interconnector is constrained-on. As a result of increased dispatch risk, these generators are likely to offer less volume into contract markets.

On balance, it is not possible to say whether the volume of contracts offered in a particular region would increase or decrease as a result of PFC. However, firmer IRSR units would, at the margin, improve the ability of parties from other regions to offer contracts at a particular RRN. Hence, the number of parties offering contracts at a particular RRN may increase.

PFC requires further development and consultation before the Commission would be comfortable recommending it for the NEM. The Commission intends to consider the approach further prior to the publication of the Final Report. The Commission would therefore welcome submissions, including from stakeholders not directly impacted by this proposal such as network businesses, retailers and traders, with regard to:

- The proposed design of the PFC mechanism, including the circumstances and threshold of its application;
- Whether PFC should be adopted as an alternative to the option of zero flow clamping with a $100,000 threshold, or should operate alongside zero flow clamping depending on the circumstances; and
- The Commission's observations of the impact of PFC as outlined above, and any other impacts not considered by the Commission.

5.3.3 Firming-up IRSR units through an external source of funds

The final set of options for firming-up IRSRs is to supplement the accumulated residues payable to unit holders with an additional source of funding. The Commission's position on the funding of negative settlement residues is a limited form of an external funding approach. However, the principle could be applied more extensively, at the extreme by making IRSRs 100% firm by funding any shortfall due to network limitations or negative settlement residue through some form of customer uplift. Whilst this would substantially reduce inter-regional trading risk, the Commission's view is that the cost to customers would be prohibitive and would represent a major policy change to how the NEM operates. It is not, therefore, developed any further in this draft report.

The exception to this position relates to the Commission observing the possibility of Rule-based arrangements in which individual generators or groups of generators elect to contribute funds to the IRSR pools in certain circumstances. An example relating to Southern Queensland can be used to illustrate this type of arrangement. Under the current Rules, these generators face the risk of being constrained-off through clamping when there are negative residues. This can occur when the Tarong constraint (within Queensland) binds, the RRP is relatively high, and the Southern Queensland generators submit low-priced bids in an attempt to be dispatched. Under this co-incidence of circumstance, the interconnector could be dispatched in a counter-price direction.

If the risk of being constrained-off were a sufficiently material problem for the Southern Queensland generators, they might in some circumstances prefer NEMMCO not to clamp, and choose to fund the negative residues themselves. In other words, interconnector flows would continue to be counter-price, but the intra-regional generators would pay into the IRSR fund the difference between the (higher) exporting region price and the (lower) importing region price. These generators would effectively receive the importing region RRP on that proportion of their output that contributed to the counter-price flows. This would make the IRSRs as firm as they would be under clamping, but would avoid the need for a physical intervention in the dispatch.

The Commission notes that there are substantial implementation issues to resolve in developing the detail of such an option (see Chapter 4 for more detail of the nature of the issues) given that it is a form of locational congestion pricing. It therefore questions whether such an intervention is warranted given the materiality of the issue potentially being addressed. However, the Commission can also see potential merit if it could be implemented in a transparent and non-discriminatory manner, and if it obviated the need for physical interventions in dispatch. The Commission would welcome views from stakeholders on whether such a proposal is practical and/or warranted.

5.4 SRA design

The Commission has also considered incremental improvements to SRAs that could improve their flexibility and hence their usefulness. Options considered have included longer- and shorter-dated IRSR units, peak and off-peak IRSR units and the sale of some units further in advance.

Of these options, the Commission considers that only the option to sell units further in advance has merit. The benefits of the other options could be obtained by repackaging the existing SRA product, which can be done by market participants themselves or by financial intermediaries.

The Southern Generators and Origin provisionally supported extending the duration of IRSR instruments. The Southern Generators highlighted that the value of longer-term IRSR units would depend on their firmness. This would, in turn, depend on the approach ultimately adopted for managing material congestion in the NEM. Meanwhile, the EUAA cautioned that improved risk management instruments may be used for speculative purposes rather than to facilitate the management of basis risk on wholesale supply contracts.

The specific option of interest to the Commission is an extension to the lead-time from SRAs to the period over which IRSR units applied, from 12 months to 36 months. That is, participants would be able to buy some IRSR units up to 3 years in advance rather than 1 year in advance. The Commission believes the Settlement Residue Committee (SRC) remains the most appropriate group to determine the size of each tranche of units available for auction, but would expect the majority of units would still be reserved for the nearer-term auctions.

The Commission believes that auctioning some IRSR units further in advance could help IRSR units become more useful for participants seeking to plan and hedge their longer-term contract positions. It would provide further options for participants when structuring their long term portfolio. The Commission also notes that there would be little downside to implementing this proposal. Implementation costs would be minimal and any units available for sale 3 years in advance that were not sold would be made available in the nearer-term auctions.

Recommendation 5:

That several tranches of IRSR units be made available for auction up to 3 years in advance of the relevant IRSR quarter, with the detailed development of release profile being established through the SRC.

This page has been intentionally left blank

6 Information and Constraint Formulation

This chapter deals with two related issues: (a) the development, formulation and management of constraints by NEMMCO and (b) the availability of information on the incidence and materiality of congestion.

The package of recommendations in this chapter will provide greater transparency, predictability and consistency in NEMMCO's management of constraints. This in turn will improve participants' ability to predict the emergence and impact of congestion, and will enable participants to develop more appropriate measures to manage the risks resulting from congestion.

The package of recommendations will also provide enhanced information on the incidence, location and materiality of congestion. This information will not only assist investors to consider congestion when locating new investment and encourage innovation in the management of congestion, but it will also ensure that policy makers in the future have a better basis for policy formulation around issues of efficient management of network congestion.

6.1 Constraint formulation

This section recommends formalising NEMMCO's use of fully co–optimised constraint formulation to improve the certainty and predictability of the way in which constraints operate in the dispatch process governed by NEMDE[75].

As explained in Chapter 2, network constraints occur when flows on network elements reach their limits. These limits are determined by TNSPs and reflected in the dispatch through the formulation of constraint equations by NEMMCO consistent with the physical limits (and subject to a due diligence process). Constraint formulation refers to the way in which the influence of different variables on flows over transmission elements is mathematically represented in the programming of NEMDE. For example, increased output by a particular generator may increase (or decrease) flows on a certain transmission element. The extent to which this occurs is represented or controlled by the coefficient on that generator's output in a constraint equation. Similarly, greater flows across an interconnector may increase (or decrease) flows on a transmission element. This can also be represented or controlled by a coefficient on the interconnector flow variable in a constraint equation.

The way in which a constraint equation is formulated can vary. Terms on the left-hand side (LHS) of a constraint equation are those that NEMMCO can control within each 5-minute dispatch interval, while terms on the right-hand-side (RHS) cannot be directly controlled by NEMMCO in each dispatch interval.

In the past, NEMMCO sometimes treated interconnector terms differently from generator output terms. For example, in some cases it applied an "option 1"

[75] Refer to section 2.2.1 for a description of NEMDE.

formulation, in which interconnector flow terms are placed on the RHS of a constraint equation.

However, more recently, NEMMCO has adopted the use of a "fully co-optimised" constraint formulation, meaning that all terms are placed on the LHS that may be directly controlled by NEMDE. NEMMCO argued that the direct control of all dispatchable terms in a constraint equation enables it to better manage system security and more fully utilise the network through lower safety factors.

Use of fully co-optimised constraint equations was supported by the introduction of Part 8 of Chapter 8A of the Rules, which requires NEMMCO to "determine and represent constraint equations in dispatch which may result from limitations on both intra-regional and inter-regional flows." This Rule was put in place as a derogation at the time because the MCE was still in the process of developing its policy position in relation to constraint formulation. NEMMCO has since completed reformulating NEMDE constraint equations to the fully co-optimised formulation.[76]

In its 2005 Statement on Transmission[77], the MCE outlined its policy decision in support of the fully co-optimised constraint formulation. This decision was based on advice from the MCE consultant Charles River Associates, who made the following recommendation in their final report to the MCE

> "On the basis that no change to the current economic objective of the five-minute spot market dispatch process is made, NEMMCO should apply the Direct Physical Representation (DPR, or "fully optimised") form of constraints (Option 4/5) to all network constraints. The Code should be amended to confirm this."[78]

The Commission is of the view that given the MCE's Statement on Transmission and the absence of any widely held view amongst participants in favour of a different method of constraint formulation it is no longer appropriate that the Rules dealing with constraint formulation be contained in a derogation. That is, the substance of the Part 8 derogation relating to fully co-optimised constraint formulation should be moved into Chapter 3 of the Rules.

The Commission understands that as a result of this proposed Rule amendment, any future adoption of a different method of constraint formulation will only be implemented through the Rule change process. The Commission believes this would be an appropriate state of affairs including because the method of constraint formulation can directly affect the manner in which generation is dispatched and priced, and therefore should be predictable and transparent. The Rules currently distinguish between inter-regional constraints and intra-regional constraints. The distinction between intra-regional and inter-regional constraints has little practical

---

76 Some outage constraints will not be re-formulated until the outage for which the constraints are required is next scheduled.

77 MCE, *Statement on NEM Electricity Transmission*, May 2005.

78 Charles River Associates, *NEM Transmission Region Boundary Structure*, pp.26.

significance in the Rules.[79] Given the Commission's recommendation to "hardwire" a requirement for fully co-optimised constraint formulation in the body of the Rules, there appears to be no logical reason for maintaining this distinction.

The Commission therefore believes that all references to "inter-regional constraints" and "intra-regional constraints" could therefore be replaced with "network constraints". This would enable clauses (a) and (b) of Part 8 or Chapter 8A to be deleted without preventing NEMMCO from using fully co-optimised constraint formulation.

The one place in Chapter 3 of the Rules where intra-regional constraints are referred to in isolation of inter-regional constraints is in pricing for constrained-on generation (Rule 3.9.7). The Rules are arguably inadequate with regard to this provision because generators may be constrained-on where a constraint that includes interconnector terms binds. Therefore it appears to the Commission that removing the distinction between inter-regional and intra-regional constraints for Rule 3.9.7 would improve the integrity and clarity of the Rules.

Removing the distinction between inter-regional constraints and intra-regional constraints only provides NEMMCO with the **option** to use fully co-optimised constraint formulation. The MCE Transmission Statement goes one step further than this by **requiring** NEMMCO to consistently use fully co-optimised constraint formulation. A new Rule in Chapter 3 will be required to give effect to this.

However, the Commission recognises that there are circumstances under which an alternate constraint formulation will be necessary to either manage counter-priced flows[80] or to manage system security[81]. Consequently, the new Rule will be drafted to allow NEMMCO to implement an alternate constraint formulation in limited circumstances. The Commission proposes that a Rule be adopted which permits NEMMCO to use an alternative formulation where NEMMCO reasonably determines that the alternate constraint formulation is necessary to meet system security or to manage negative settlement residues.

While the Commission understands that NEMMCO may reasonably determine that an alternative formulation is appropriate, the circumstances in which that may occur and the manner in which an alternative formulation would be developed and implemented must be transparent and predictable to the market.

Consequently, the Commission proposes a Rule that requires NEMMCO to develop and comply with constraint guidelines proposed in Section 6.2.2, which would detail the circumstances in which alternative constraint formulation is necessary to meet system security or manage negative settlement residues, and must also describe the alternate constraint formulations that may be used. NEMMCO would be required to

[79] Chapter 2 provides further discussion on constraint types including trans-regional constraints.

[80] Chapter 5 provides further discussion on alternative constraint formulation to manage negative residues.

[81] NEMMCO currently describes circumstances under which system security of not appropriately served by the fully co-optimised constraint formulation in its paper "Network and FCAS Constraint Formulation" located at www.nemmco.com.au/dispatchandpricing/170-0040.pdf

develop these guidelines in accordance with the Rules consultation procedures under Section 8.9 of the Rules.

Recommendation 6:

Include within Chapter 3 of the Rules the requirement for NEMMCO to use fully co-optimised network constraint formulation to the extent practicable, except where NEMMCO reasonably determines that an alternative constraint formulation is necessary to meet system security requirements or to manage negative settlement residues provided that NEMMCO's use of an alternative constraint formulation is consistent with the guidelines referred to in Section 6.2.2.

6.2 Information

6.2.1 Background

As noted above, the provision of additional, more timely or better quality information may assist participants manage trading risks arising due to network congestion and may reduce the occurrence of congestion in the longer term including through better locational signals for the building of new transmission and generation capacity.

All submissions to the Directions Paper supported increased information provision to improve congestion management, although the transmission owners, ETNOF, raised a number of issues. ETNOF stated that when examining possible information provisions for TNSPs, the Commission needed to recognise that: (a) the provision of information is not costless; (b) information must be meaningful and practical to provide; and (c) information should only be provided on a Rules-mandated basis where it can be shown that the required information will not be delivered as a result of competitive forces and/or provision on a user-pays basis. The Southern Generators supported the provision of additional information regarding congestion, but considered that it may have limited effectiveness as it would not address the problem of a lack of certainty of access to the regional reference node faced by a new generator.

Information is currently made available to assist market participants to understand and manage congestion. The scope of currently available information is outlined in Appendix H. The Commission has considered how amendments to the Rules may improve or refine the extent and nature of information made available in order to enhance the ability of market participants to understand and manage the trading implications of network congestion. Two specific areas have been identified where the Commission considers change to be warranted are: (1) information on constraint equation development and invocation; and (2) Information on the incidence and patterns of mis-pricing. These are discussed in turn below.

6.2.2 Constraint equation development and invocation

The Commission has received a number of submissions[82] in relation to the quantity and quality of available information with respect to the development and invocation of constraint equations. Similar concerns were raised by participants during bilateral discussions with AEMC staff. Questions surround:

- The methodology and process for how constraint equations are developed, formulated and implemented by NEMMCO in response to network augmentations, new network support agreements, the connection of major new loads or generators and in the event of network or plant outages; and

- The real-time flow of information regarding how, why and when particular constraint equations are invoked or revoked by NEMMCO.

Clearly, there will be some overlap between the approach for the development, formulation and implementation of new or modified constraints and the provision of information regarding the invocation and revocation of particular constraints. Nevertheless, the Commission sees benefit in discussing each topic separately.

6.2.2.1 Methodology and process for developing, formulating and implementing constraint equations

Generic constraint equations are used in the dispatch process to manage network limitations (under both system normal and outage conditions), ancillary service requirements, generator non-conformance, network security violations, generator ramp rates, interconnector rates of change, and other discretionary events. Each of these constraint equation types can have a material effect on the dispatch of a generator (or load), and the price at which that generator is settled.

Taking network constraints for example, constraint equations may need to be created or modified due to changes in network transfer capability. Activities such as transmission investment will have an impact on the effective level of network transfer capability, which will need to be reflected in changes to the limits or coefficients used in constraint equations. The existing process involves, for example:

- The relevant TNSP notifying NEMMCO of the change in transfer limits resulting from a change to the physical network or assets connecting to its network;

- NEMMCO carrying out a due diligence assessment of stability related limits; and

- NEMMCO formulating and then implementing a new or amended constraint equation(s) that reflects the change.

This process is not formalised within the Rules. The method by which constraint equations are developed, formulated, and implemented is outlined in various NEMMCO documents, largely published voluntarily by NEMMCO. The Rules do

---

[82] Newcastle Group, p.8; Macquarie Generation, p.1,5.

not require NEMMCO to following the processes and methodology outlined in the above mentioned documents, and limited requirements to keep participants informed during the process.

Some participants, such as members of the Newcastle Group,[83] have suggested that the process of constraint formulation is not as transparent as it should be and that NEMMCO should consult on the specification of each constraint equation. Many participants during bilateral discussions with the Commission expressed concern regarding the risks created by the uncertainty and lack of understanding surrounding the development and implementation of constraint equations.

Given the potential significant commercial impact of the way in which constraint formulations are developed and implemented, the Commission considers that these are matters which should be subject to a high degree of transparency and predictability for market participants.

The Commission considers that while specific consultation on each individual constraint equation is unlikely to be practicable, there is a case for obliging NEMMCO to develop, formulate and implement constraint equations in accordance with published "constraint guidelines".

The constraint guidelines should provide sufficient information for participants to understand NEMMCO's approach to constraint equation development, formulation and implementation, and should assist Market Participants to assess the impact of constraints on dispatch and pricing. The Commission is of the view that the content of the guidelines should be determined by NEMMCO in consultation with participants. However the Commission considers that the following information should be included in the NEMMCO guidelines, at a minimum:

1. Constraint Equation Development – the process by which NEMMCO identifies or is advised of the need (e.g. by a TNSP following its determination of technical limits) to create or modify a constraint equation, including communication channels with other participants to obtain and disseminate information, and the methodology followed by NEMMCO in determining equation terms and coefficients;

2. Constraint Equation Formulation – the methodology followed by NEMMCO in selecting the form of constraint equation, including the location of terms on each side of the equation; and

3. Constraint Equation Implementation – the process for applying, invoking and revoking constraint equations in different circumstances, such as where network outages require the invocation of different constraints for a specific period of time. This should also outline at which stages of the process participants are kept informed.

[83] Reference

NEMMCO currently publishes many useful documents describing various aspects of constraints (including FCAS constraints). Examples include the following titles:

- Network and FCAS constraint formulation;
- Constraints guide – FCAS constraints;
- Guide to FCAS constraint analysis;
- Basslink Energy and FCAS Equations;
- Operating procedure – Dispatch; and
- Operating procedure – Generic constraints due to network limitations.

The Commission considers that comprehensive constraint guidelines would include a consolidation of these existing documents, and would include an outline of NEMMCO constraint policies that currently reside in NEMMCO operating procedures. Ideally, the constraint guidelines would be a "one-stop shop" for participants seeking information on any aspect of constraints.

Recommendation 7:

That NEMMCO be obliged to:

- **Develop constraint guidelines outlining the methodology and process to be followed when developing, formulating and implementing constraint equations to assist participants to assess the impact of constraints on dispatch and pricing;**
- **Comply with its published constraint guidelines; and**
- **Consult with stakeholders when developing or modifying those guidelines.**

6.2.3 Real-time information flow relating to the application, invocation and revocation of constraints

A number of submissions received by the Commission have suggested that there is a lack of transparency over the timing with which constraint equations are invoked or revoked in response to events such as network outages. Market participants need to take physical or financial measures to manage the impact of constraints, and when the timing of constraints cannot be accurately predicted, market participants can find themselves exposed to both physical and financial risk. The NGF supported the provision of more detailed congestion information that would allow participants to: a) prepare for occasions when constraints occur; b) ensure trading strategies were consistent with congestion risks; and c) better assess current and future market access at key locations around the NEM.

The Commission considers that some of these concerns will be addressed by the publication, by NEMMCO, of guidelines covering its intended process for invoking and revoking various types of constraint equations.[84] This should increase the predictability of NEMMCO action. However, this will not itself ensure participants are provided with timely notification of events that lead to different constraints being invoked or revoked.

A key reason why different constraints might be invoked is to reflect network outages. For example, a different constraint may be implemented when a transmission asset is taken out of service for maintenance. Participants are presently advised of outages through several NEMMCO and TNSP publications. These include the Planned Outage Schedule (POS) published jointly by NEMMCO and the TNSPs each month pursuant to Rule 3.7A, the Network Outage Schedule (NOS) published by NEMMCO and updated every four hours, and Market Notices.

Many participants stated that the timeliness and quality of the current information flow was inadequate for them to plan their physical and financial trading positions.[85] Specific concerns included a lack of real-time information on network outages affecting inter-regional flows, lack of information on last minute changes to the timing of outages, inadequate notification of the end of outages, delays in NEMMCO passing on outage information to participants and insufficient information to fully assess both the physical and market impact of an outage.

The NOS is currently published voluntarily by NEMMCO. The NOS and POS provide market participants with information that is potentially very important to their commercial and operational decisions. Consequently the Commission believes the requirement to publish the information provided in the NOS and POS should be formalised and NEMMCO should be obliged under the Rules to publish sufficient information on events affecting constraints to enable participants to understand, predict, and appropriately respond to those events.

The NOS and the POS currently report on network outages only. However outages are not the only reason why different constraints might be invoked. For example, the set of constraints being invoked might change if a new transmission asset comes into service, if new generation capacity starts to operate, if existing generation capacity ceases to operate or if new industrial load connects to the network. All of these events have relevance to the ability of market participants to understand and manage trading risks associated with network congestion. Currently an information gap exists spanning the time between the TNSP's Annual Planning Report, which notifies the market of the TNSP's intended response to a constraint, and the time when NEMMCO implements the revised constraint formulation. At each stage of the process, participants potentially face uncertainty over the methodology and timing of the process.

The Commission believes that improved clarity and predictability regarding the impact of a TNSP's actions on likely transfer capability, and on its ultimate

[84] Refer to section 6.2.2.

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

expression in constraint equations will enable participants to better manage their physical and financial trading risks. The Commission therefore considers that NEMMCO should to be required to publish information about events other than network outages that may result in different constraint equations being formulated and/or invoked. This would help provide a richer and more continuous flow of information to participants. The nature of events for potential inclusion could be the commissioning of new network, generation and load assets, as well as the implementation of other changes such as network support and NCAS contracts. This will help fill in the majority of the gaps in the current flow of information to participants.

The NOS does not currently provide participants with information to track changes in the timing of outages and the reasons for changes to outage start and end dates. The Commission considers that this additional information should be provided to better equip participants to predict changes to the timing of outages. This information may also place greater discipline on TNSPs and/or NEMMCO to accurately schedule outages, as far as practicable.

NEMMCO currently does not issue market notices to inform market participants when constraints affecting network transfers purely within a region are changed (i.e. when a distribution asset is returned to service following an outage). Market participants have indicated that they rely on informal relationships with network business to understand when they are affected by such transfer limits. The Commission expects the proposed enhancements to the NOS should rectify this problem.

Recommendation 8:

That the Rules be amended to:

- **Require NEMMCO to develop and publish an information resource that assists Market Participants to understand and predict the nature and timing of events that are likely to materially affect constraints in the dispatch process. NEMMCO must develop this information resource in consultation with industry;**

- **The "events" referred to above should include at a minimum, network outages, commissioning (or decommissioning) of new generating units, loads or network assets and new or modified network support constraints;**

- **NEMMCO must publish the information required above on a timely basis and must publish updates to that information provided under this Rule as soon as practicable;**

- **The information resource must be transparent and give Market Participants confidence that all relevant information is published in a timely manner;**

- **In developing or changing this information resource, NEMMCO must consult with industry; and**

- **Oblige TNSPs and other Registered Participants to provide that information required by NEMMCO to develop this information source.**

6.3 Mis-pricing

In the Directions Paper, the Commission discussed the potential for NEMMCO to publish information on mis-pricing[86] of generation to enable participants to better manage congestion in the medium to long term. The Directions Paper suggested that this information could:

- Be either in the form of published nodal prices or differences between the RRP and nodal prices;
- Identify whether the constraint that caused the mis-pricing was an outage constraint or a system normal constraint; and
- Identify the network element or cut-set on which the limitation arose.[87]

The Southern Generators supported the publication of nodal prices. However, they expressed concern that potential entrants may be unfamiliar with the idiosyncrasies of NEM pricing and may not appreciate that generators are not actually settled at their nodal price. Therefore, the publication of mis-pricing data ought to be accompanied by explanation to ensure it is not misinterpreted.

Major Energy Users Inc noted that publishing information on future levels of congestion to assist investment decisions might expose the provider to risks if the information later proved to be incorrect. Powerlink expressed the concern that any obligation to provide information not expose the TNSPs to the risk of being responsible for the wisdom of investment decisions made by new investors.

Regarding the publication of “nodal prices”, NEMMCO considered that this would require a very substantial ongoing commitment of resources.[88] It suggested that information on mis-pricing based on constraint shadow prices would be simpler to produce, and stated that this mis-pricing information was likely to be just as useful to market participants as information on nodal prices. NEMMCO noted that it already published significant constraint information and commented that there would be merit in exploring how the provision of further data on mis-pricing could be expected to improve participants’ responses to congestion.

The Commission believes that any obligation on NEMMCO in the Rules to publish information should take into account and balance both the potential benefit to participants and the extent of the burden placed on NEMMCO. The Commission agrees that routine publication of mis-pricing information would enable congestion to be better managed in the longer term and would be a proportionate response to the issue.

---

[86] The concept of mis-pricing is described is Section 2.2.2.

[87] Directions Paper, p.60.

[88] Nodal prices are calculated as the marginal cost of supply at each node (refer to Section 2.2.2 for a more detailed explanation of nodal pricing). To determine accurately all nodal prices in the NEM, NEMMCO would probably need to run a full-network dispatch and pricing model in parallel to the current dispatch model.

While the Commission has not found a case for substantial changes to the NEM to manage congestion in the short to medium term for the reasons explained in Chapter 3, it is conceivable that in the longer term more substantial reforms to manage congestion may be appropriate. The establishment of a new data series could thus be a valuable aid to policy-making in the future. The mis-pricing information produced by NEMMCO to assist the Commission assess the materiality of congestion[89] is representative of the type of information the Commission believes would be of value to the market.

Mis-pricing information would also be of value in identifying specific points of congestion, where targeted measures could be implemented to assist the management of location-specific congestion. This may include, for example, greater use of network support agreements to relieve congestion for market-benefit reasons in addition to reliability reasons. Mis-pricing information would assist participants identify areas where they themselves could negotiate such agreements. This information would also assist policy makers to identify where incentives were not sufficient to promote such a response from the market.

Finally mis-pricing information would be of value to investors as a tool to be used early in the investment decision-making process when considering the location for investment. While the Commission understands that the location of investments are based on a range of factors including access to fuel and water and environmental considerations it expects that prior to committing to the location of an investment an investor would undertake a more comprehensive assessment of congestion at its preferred location. Mis-pricing information would be of value in initial conceptual assessments only.

Recommendation 9:

- **That NEMMCO develops a methodology in consultation with participants for the production of mis-pricing information that covers all material congestion in the NEM;**
- **That NEMMCO publishes mis-pricing information on a quarterly basis; and**
- **That NEMMCO's other resource commitments be taken into account when establishing a commencement date for this requirement.**

[89] See Chapter 3 on the Materiality of Congestion in the NEM.

This page has been intentionally left blank

7 Transmission

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

In 2006, the Commission reviewed and substantially reformed the Rules relating to the economic regulation of transmission. The relationship between the CMR and transmission is more focused, involving analysis of whether incremental changes to transmission regulation might reduce the financial and physical trading risks associated with network congestion, or enable participants to manage these risks more efficiently. This chapter addresses that more focused question.

7.1 Background

7.1.1 The relationship between transmission and congestion

The amount of network congestion at any point in time is a function of the ability of the transmission system to accommodate the pattern of power flows emerging from the dispatch process, which in turn is dependent on the interaction of the demand for and supply of electricity in various locations of the NEM. An enhanced ability to handle power flows means, other things being equal, a lower likelihood of network congestion occurring and hence, reduced physical and financial trading risks for participants.

The ability of the network to handle power flows is referred to as its “capability” and it is capability that comprises the service provided by TNSPs to the market. Capability is a dynamic variable that depends on both the technical design limitations of individual network elements – known as their “capacity” – as well as the way in which those network elements are operated collectively under different power system conditions.[90]

Factors influencing network capability include:

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

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

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

One of the key findings contained in Charles River Associates modelling report on NEM Regional Boundary Issues was that small changes to the network transfer capability of the existing network can substantially ease congestion and can lead to a dramatic drop in both the level of nodal prices and their volatility. Thus, enhanced network capability, particularly at certain times, may help alleviate the physical and financial trading risks of congestion.

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

- Investing to increase the capacity of network elements;

- Maintaining network elements to ensure they are capable of operating to their technical limits (ie at their capacities);

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

- Engaging in other activities, such as the procurement or provision of Network Support and Control Services to enhance network capability (NSCS – see section 7.2.2 below).

7.1.2 The regulatory framework for transmission

Chapter 6A of the Rules addresses the economic regulation of transmission services and sets out the provisions governing revenue allowances and pricing methodologies. These provisions were intended to strengthen the financial incentives for efficient decision-making by both TNSPs and participants in relation to investment in transmission, generation and load facilities.

7.1.2.1 Revenue

The Revenue Rule classes transmission services into two broad categories — Prescribed Transmission Services and Negotiated Transmission Services — for which the scope and form of regulation differs. The Rules provide for a CPI-X revenue cap to be set for each company for Prescribed Transmission Services. The revenue cap is set every five years, using a building blocks cost of service approach, are a level commensurate with efficient operating expenditure, and depreciation and return on efficient capital expenditure. This framework provides a financial incentive for the company to operate more efficiently because it retains (or is exposed to) differences between actual and allowed revenues for the duration of the revenue period. Charges for Negotiated Transmission Services are, in contrast, are set under a “negotiate-arbitrate” framework.

Chapter 6A of the Rules provides for the AER to develop a service target performance incentive scheme, whereby between 1% and 5% of each TNSP’s regulated revenue is "at risk", contingent on the TNSP's performance against a suite of performance measures. Rule 6A.7.4 requires the AER to publish the Service Target Performance Incentive Scheme by 28 September 2007. The scheme must comply with the principles set out in Rule 6A.7.4(b).

The scheme principles are intended to encourage TNSPs to provide greater reliability of the transmission system at those *times* when it is most valued by transmission network users and in respect of those *network elements* that are most important to the determination of spot prices. These objectives relate directly to the provision of transmission capability on a day-to-day basis – and therefore can contribute directly to the efficiency of the congestion management regime.

In January 2007, the AER published its first proposed set of guidelines for the service target performance (STP) scheme.[91] The AER's accompanying Issues Paper proposed a scheme that was a continuation of the existing service standards incentives framework – and would apply in respect of the following network-based parameters:

- Transmission circuit availability;
- Loss of supply event frequency; and
- Average outage duration.

The AER proposed that the maximum revenue at risk be initially 1 % of a TNSP's maximum allowed revenue (MAR). TNSPs would be required to propose the relative weightings of exposure of the 1% across the three network parameters. The AER noted that this level of revenue at risk may be conservative over the long term, but said that it wished to be cautious about exposing TNSPs to additional risk or uncertainty as the operation of the service standards regime and the existing guidelines had not undergone any review.

In June 2007, the AER published a further Issues Paper proposing service incentives linked to its existing cost of congestion measures. The AER's initial proposal is to incentivise TNSPs to both:

- Minimise binding constraints that have a marginal cost of constraint[92] higher than a threshold of $10/MW; and
- Provide longer notification of planned outages. The incentive payments are weighed according to the length of notice given. The AER proposes basing the incentive on an average of TNSP performance over a three year period.

---

[91] Australian Energy Regulator, *First Proposed Electricity Network Service Providers Service Target Performance Incentive Scheme*, Version No.01, January 2007.

[92] The marginal cost or value of a constraint is the change in the cost of producing sufficient electricity (based on bids and offers submitted) to meet demand brought about by the binding of a particular constraint. It broadly equals the difference in generation bids between the generator whose output has to increase and the generator whose output is decreased as a result of the binding of the constraint. For constraints that are inter-regional, the marginal value usually equals the RRN price difference between the importing region and the exporting region.

The first schemes under the amended Rules are due to be finalised by AER shortly, allowing them to be applied to the forthcoming Transend, Energy Australia and TransGrid revenue reviews.

7.1.2.2 Pricing

The Pricing Rule Determination for Chapter 6A outlined the regulatory framework and principles for setting prices for Prescribed Transmission Services. The regulatory framework section in the Pricing Rule Determination stated the Commission's provisional position on four issues that were intended to be subject to review in light of the findings of the CMR:

- "generators should pay the costs directly resulting from their connection decisions, that is, a 'shallow connection' approach should be maintained;
- it is not appropriate at this stage for generators to contribute to the costs of the shared network through prescribed generator TUOS charges;
- Cost Reflective Network Pricing (CRNP) and modified CRNP are appropriate locational pricing methodologies, however, there should be scope for these to be developed further in future; and
- to some extent price structures should be specified in the Rules with additional guidance provided by the AER".[93]

The Rules maintain a "shallow" connection charging approach for new generation. This means that generators only need to pay for the costs of their immediate connection to the transmission network and are not required to contribute to the costs of downstream augmentations from which they may benefit, so long as those augmentations satisfy the Regulatory Test. At the same time, generators may request TNSPs to undertake downstream augmentations that are not required to serve load requirements, but must pay the relevant costs and are not entitled to receive explicit financial or physical rights to the incremental transfer capability.[94]

Other provision relating to pricing are contained in Chapter 5 of the Rules. These provisions enable TNSPs to contract with connection applicants or participants for the provision of particular services. Both Rules 5.4A and 5.5 provide for negotiated use of system charges to be levied on "connection applicants" to reflect the incremental costs (or savings) of any augmentations or extensions to transmission or distribution networks that arise from their new connection (see Rules 5.4A(f)(3)(i), 5.4A(f)(3)(ii), 5.5(f)(3)(i), 5.5(f)(3)(ii)).

---

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

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

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

7.1.3 Investment planning and the Regulatory Test

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

The Rules also require TNSPs to subject proposed network investments to the AER's Regulatory Test, to ensure their investments represent the most efficient option compared with a range of genuine and practicable alternatives, including demand side management and other local generation solutions. TNSPs are only permitted to undertake those investments that satisfy the AER Regulatory Test.[95] The Regulatory Test comprises two alternative "limbs", one of which an investment must satisfy prior to being able to proceed. These are the:

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

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

In November 2006, following a review of the market benefits limb, the Commission made a Rule outlining principles for a revised Regulatory Test.[96] The new Rule imposes much more specific principles for the market benefits limb of the Test, including a requirement for TNSPs to publish a request for information where they are assessing a potential "large new transmission network investment". This should help ensure that all relevant options are considered under the market benefits limb of the Test.

In March 2007 the Rules were amended to provide the Commission with the power to direct TNSPs to undertake a Regulatory Test assessment for a particular network problem or transmission investment under certain circumstances. This is known as

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

[96] AEMC 2006, *Reform of the Regulatory Test Principles*, Final Rule Determination.

the Last Resort Planning Power (LRPP).[97] Its purpose is to ensure that appropriate consideration was given to congestion-relieving transmission investments in circumstances where TNSPs may lack incentives to apply the Regulatory Test. Importantly, the power of direction may only be exercised by the Commission as a "last resort".

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

- Improved locational signals to generators;
- A stronger incentive framework for TNSPs, and
- An improved national transmission planning mechanism to better coordinate and integrate the development of the national power system.

In its communiqué of 13 April 2007, COAG announced its decision to establish an enhanced planning process for the national electricity transmission network to promote more strategic and co-ordinated development of the transmission network and to assist in optimising investment between transmission and generation across the power system. On 3 July 2007, the MCE directed the Commission to conduct a review into development of a detailed implementation plan for a national transmission planner.

7.2 Potential areas of further reform

The previous section sets out the context within which the Commission has considered the case for recommending under CMR further reforms to the framework for transmission. In general, the Commission is of the view that the existing regime is recently reformed and should be given time to work. Further, the specific issues relating to transmission planning and the Regulatory Test are to be examined in the context of the Commission's work on the national transmission planner.

However, the Commission has considered a number of specific areas where it wishes to make recommendations or observations. These are:

- Measures of transmission capability;
- The framework for the provision of Network Support and Control Services; and
- Transmission pricing.

97 AEMC 2007, *National Electricity Amendment (Transmission Last Resort Planning) Rule 2007*, Rule Determination.

7.2.1 Measures of transmission capability

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

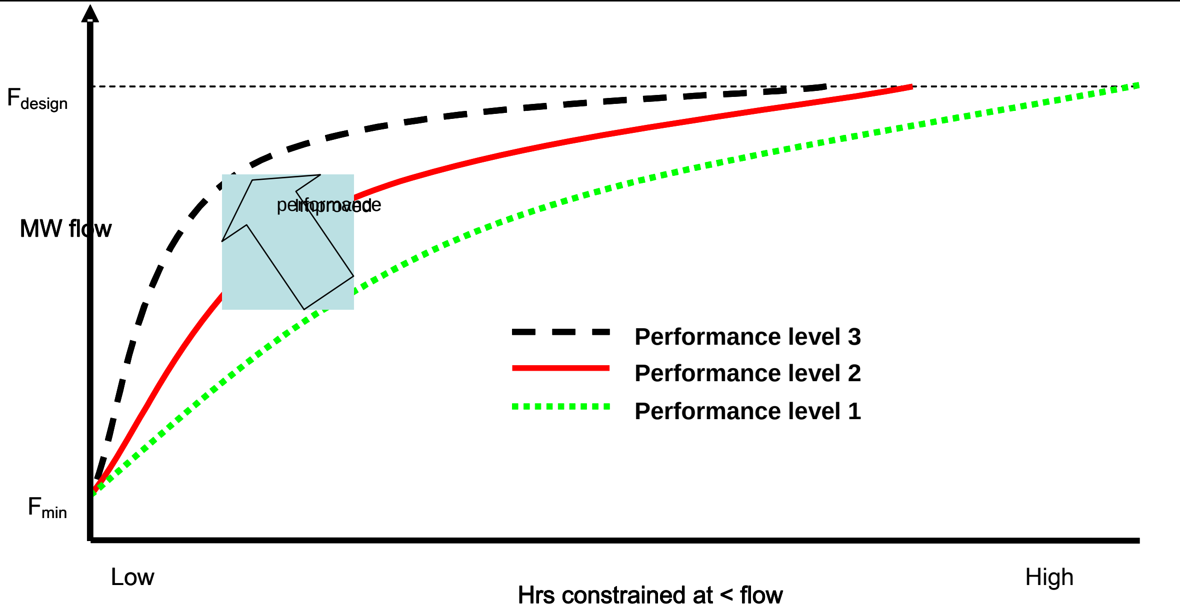
The Commission observes that a limiting factor on promoting efficient transmission services from the perspective of congestion management is the absence of measures of the "outputs" that matter from a congestion management perspective, i.e. transmission capability. The AER work program to develop system service incentives is an important element in promoting efficiency in this regard, but is necessarily based around partial output measures, e.g. patterns of outages, in the absence of more general metrics of transmission capability.

In a supplementary submission, Delta Electricity suggested making information available on connection point to load centre transfer capability and also on the network locations that can accept further generation injection without exacerbating congestion. [98] It also suggested publication of information on the cost of network augmentation to relieve any congestion caused if generation were to be injected above those levels. Delta considered this information could help investors evaluate locations for potential new connections. Submissions from TNSPs to the Direction Paper noted that information on connection point transfer capability is already commonly provided as part of the connection application process, and questioned the value of the other information cited by Delta given the likely sensitivity to the assumptions being used.

In its submission to the Direction Paper, NEMMCO commented that it considered that network capability could not be adequately described by a single number, and put forward some suggestions, e.g. a constrained flow-duration curve. This curve would plot level of flow when binding against the number of hours binding at each level of flow. An example of such a curve is provided below:

[98] Delta Electricity, Supplementary submission, Congestion Management Review, 9 November 2006.

Figure 7.1



The Commission considers that more disaggregated information (e.g. for a much larger number of flow paths) on network capability would confer benefits beyond enabling a potential enhancement of a TNSP incentive scheme. It would also improve the ability of market participants to predict the likelihood of congestion and could also provide greater general transparency to the market on what outputs are delivered by TNSPs. It considers the costs of publishing the additional information requested under the Delta Electricity Proposal outweigh the possible benefits from making this information available to potential investors.

The Commission, therefore observes that work should be undertake to develop better measures of transmission capability and that this should be given effect through obligations in the Rules. There is however, a question as to which party should have primary responsibility. There are a number of options, reflecting the multiplicity of potential uses for such measures. For example, the AER could lead the process with NEMMCO providing support technical advice, or NEMMCO could lead with a requirement to consult closely with the AER. The Commission notes that such measures might also have relevance in the context of a National Planner, although it is too soon to know the precise nature and form of any such interactions. The Commission will keep this under review as consultation on the National Planner proceeds. In any event, the Commission would welcome views on:

- Whether there is a need for more sophisticated measures of transmission capability, and what purpose such measures would serve;
- How such measures should be specified; and
- Who should have responsibility for developing, producing and publishing such measures.

7.2.2 Network Support and Control Services

Under the regulatory regime for transmission revenues, TNSPs may choose to make expenditures on network or non-network solutions, either of which may involve capital or non-capital expenditures. This is an important element of Regulatory Test.

The previous discussion also highlighted that transmission capability at any given point in time depends on a number of factors. One such factor is the provision of Network Support and Control Services (NSCS). NSCS are those services procured and delivered by TNSPs or NEMMCO for the purpose of managing network flows to ensure secure and reliable operation of the power system or to enhance capability and thereby delivering a market benefit. NSCS currently procured and delivered include:

- **Network Support Services** – procured by TNSPs via contracts with third parties (network support agreements (NSAs)), e.g. generators or load agreeing to be constrained on (or off) in specified circumstances;

- **Network Control Ancillary Services** (NCAS) – procured by NEMMCO via contracts with Market Participants (not TNSPs) as either reactive power ancillary service (RPAS) in the form of voltage control, or network loading control ancillary service (NLCAS) e.g. rapid generator unit loading or load tripping scheme.

In addition, TNSPs can deliver some forms of network control services from their own infrastructure, such as reactive power capability from capacitor banks or static var compensators. The provision of such services can obviate the need for agreements to be struck with market participants. Appendix I provides further detail on the provision of NSCS.

Under the Rules, NEMMCO has the ability to procure NCAS as a means of ensuring sufficient capability to support meeting the power system security and reliability standards under the Rules. NEMMCO may also procure NCAS to assist in maximising the value of spot market trading. The costs of these services are recovered as part of NEMMCO's market fees (i.e. through a general charges across the whole market). TNSPs are prohibited from submitting tenders to NEMMCO for the provision of NCAS above and beyond the levels required by jurisdiction-specific security and reliability requirements can affect the effectiveness of the current arrangements. TNSPs may, however, use NSCS as part of meeting their own reliability obligations under the Rules, jurisdictional instruments or as might be agreed with individual connecting parties through connection agreements.

The efficient procurement and delivery of NSCS is a component part of an efficient congestion management regime, although it is important to recognise the wider purposes of NSCS, e.g. in terms of system security and reliability. The development of more sophisticated measures of transmission capability will provide greater visibility on whether and how NSCS can be used to support more efficient congestion management – and refined incentive schemes can be used to reward TNSPs for the efficient use of NSCS-type solutions to the problem of delivering valued transmission capability from a congestion management perspective.

There are, however, two additional issues relating to the provision of NSCS where the Commission wishes to make observations. The first issue concerns the revenue treatment of NCSC solutions for TNSPs. The second issues concerns the status of a planned review by NEMMCO of NSCS arrangements, required under the Rules.

7.2.2.1 Revenue treatment of NCSC for TNSPs

As noted above, the efficient delivery of transmission capability by TNSPs requires consideration of all possible options for providing transmission capability. NCSC is one such option. The revenue treatment of network investment under the Regulatory has been the subject of detailed revenue, and a robust incentive-based approach has been developed. In contrast, where a TNSP adopts a non-network solution, the costs may be "passed through" to customers as if the cost of the non-network option were part of the TNSP's operating and maintenance costs.

Arguably, network solutions consequently provide a TNSP with the scope to earn a greater return than non-network solutions. This is because of the ability of TNSPs to earn a regulated rate of return on their network capital expenditure, while only being able to pass-through operating expenditures (within which most NSCS would be recovered) at cost. However, network capital expenditures also carry a risk that the TNSP will earn a reduced return if costs are over-run during that regulatory period. A non-network solution may therefore represent a lower risk/lower return option for a TNSP.

This difference in revenue treatment could potentially influence outcomes, although the Commission is not aware of any direct evidence that this is occurring. The Commission would welcome views on whether a change to the revenue treatment of non-network or NSCS solutions under Chapter 6A is appropriate as a means of equalising the financial incentives for TNSPs to develop network and non-network solutions, and views on what the changes should be. This could involve, for example, the operating cost associated with a non-network solution being 'capitalised" in some circumstances for the purposes of calculating revenue allowances.

7.2.2.2 NEMMCO's review of NCAS

As noted above NEMMCO and TNSPs both have some scope for using NSCS under the Rules. There is a degree of ambiguity over where the boundary of respective responsibilities lies and the extent of any obligation on TNSPs to consider NSCS in undertaking network planning and/or applying the Regulatory Test. In practice, the current regime could be characterised as NEMMCO acting as "NSCS procurer of last resort". Further ambiguity lies in the appropriate approach for assessing NSCS options against conventional network investment options.

The Commission strongly supports the more efficient use of NSCS as a means of providing transmission capability and believes that changes to TNSP incentives will, over time, contribute to this outcome. However, it is not obvious to the Commission that the current Rules concerning the roles and responsibilities for NSCS create barriers to this outcome. In any event, NSCS serve a number of purposes, some of which are only very indirectly related to the issue of congestion management.

Hence, while the question of roles and responsibilities for NSCS contracts is clearly an important issue for the operation of the NEM, it would appear to involve issues wider in scope than the CMR. The Commission therefore believes that these issues would need to be addressed through a separate and more focussed review.

Under Rule 3.1.4 (a1), NEMMCO is required to review and report on the operation and efficiency of spot market for market ancillary services within the overall central dispatch and on the provision of NCAS. Given the possibility of NEMMCO's NCAS review overlapping with the considerations of this Review, NEMMCO sought and received the Commission's agreement to delay the commencement of its NCAS review until the CMR draft report had been published. Given that this milestone has been reached, the Commission observes that NEMMCO's review, which should be noted is wider in scope than issues relating to congestion management, should be re-commenced. However, the Commission would welcome views on whether the NEMMCO review the appropriate forum to consider the general issue of roles and responsibility for NSCS contracts, or whether further review in a different forum is appropriate (e.g. in the context of the national planner).

7.2.3 Transmission Pricing

The charges for Prescribed and Negotiated transmission services levied by TNSPs represent one influence, among many, on generator locational investment decisions. Where generating capacity is built, or retired, affects future patterns of network congestion and the accompanying trading risks. As described in section 7.1.2.2, in December 2006 the Commission concluded its review of the framework for transmission pricing. The review supported the continuation of a "shallow" connection charging policy (i.e. that generators should pay charges reflecting the costs of providing a connection to the shared transmission system, but not for any downstream network costs). The Commission came to this view for a number of reasons.

First, the Commission noted that the nature and timing of network investment is primarily determined by prescribed reliability criteria and hence a shallow connection charging approach is consistent with the "causer pay" principle. In other words, generators do not "cause" new transmission investment to be undertaken simply by virtue of their locational decision. It is only where a TNSP considers that network investment will satisfy either limb of the Regulatory Test (such as by being the least cost means of satisfying reliability criteria) that the TNSP is permitted to make the investment and recover the costs through charges for Prescribed Transmission Services. Of course, generators are always free to fund augmentations under the Negotiated Transmission Services provisions. Effectively, this means that the arrangements implement a *de facto* deep connection charging approach for investment that is not demonstrated as being efficient.

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

Finally, the Commission also agreed with market participants that deep connection charges may create additional regulatory complexity and deter new generation investment, thereby harming competition and the long-term interests of end-use consumers.[99] The Commission did, however, undertake to review this position in the light of the CMR.

Through the CMR process the Commission has received a number of submissions relating to transmission charges, and the related issues of transmission rights. Two submissions (from Delta Electricity and Southern Generators) advocating the implementation of additional capacity or access charges for new generators, in order to expose new entrants to the incremental effect on congestion caused by their location. These are discussed in more detail below.

In addition, other parties commented on the effectiveness of the negotiated access charges clauses contained in Chapter 5 of the Rules. The National Generators Forum (NGF) considered that other connecting parties were unlikely to agree to pay charges that reduced the cost incurred by the original investor, particularly in the case of a "deep" augmentation. The NGF also considered that free rider concerns and the lack of any firm arrangements to compensate or reimburse a generator for a loss of asset value needed to be revisited.[100] AGL observed that the Chapter 5 Rules on negotiated access have not been successfully applied.[101] AGL stated that if the Rules were effectively applied, they would result in generators paying an increasing portion of total TUoS costs over time.

Delta Electricity Proposal

In a supplementary submission to the Review, Delta Electricity proposed changes to the charges faced by new generators. [102] The proposal is a form of deep connection charging. Delta proposed that new generators should pay the cost of downstream augmentations if their investment location leads to further congestion on the network. The TNSP would determine the additional cost of any long term network augmentation (LRMC) required to avoid congestion occurring. If the new generator locates where there is ample transmission access or where the network is likely to be augmented as part of the least cost plan, the LRMC would be zero. If however, the generator, for whatever reason, determines to locate where congestion does result and the LRMC is positive (and above a tolerance level), then the generator would be exposed to that cost.[103] Delta Electricity contended that such arrangements would lead to greater alignment between regulated investment in transmission and market driven investment in generation and more efficient generation location decisions.

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

100 National Generators Forum, Congestion Management Review- Directions Paper Submission, 13 April 2007, p.10.

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

102 Delta Electricity, Supplementary submission, Congestion Management Review, 9 November 2006, p.9.

103 Ibid.

There would be no explicit transmission rights under the Delta proposals, but the implicit rights for existing generators would be "irmed up". Delta also commented on the information available to prospective new generators (see section 7.2.1).

Southern Generators' Proposal

In a supplementary submission dated 23 November 2006, the Southern Generators contended that transmission rights were essential in removing or lowering existing entry barriers for new generation investment. [104] They proposed a system of explicit financial access rights which would give parties the right to a specified level of access to the local RRN or to be compensated if this level of access is not specified. They stated that this access right will not be firm, in the sense that physical access would not be guaranteed to the holder. The Southern Generators also proposed that incumbent generators would be allocated access rights but any new entrant would have to pay to obtain access rights.

This proposal from the Southern Generators for explicit financial rights providing settlement at the RRP differs from the arrangement suggested by the LATIN Group for full rollout of CSC/CSPs (discussed in section 4.3.4.1). Although both proposals have the similar goal of providing certainty for incumbent generators to have access to the RRN, the financial access rights arrangement would not include generator nodal prices. This leads to issues regarding how such access rights should be valued under the proposed arrangement. In their proposal, the Southern Generators suggested that the access rights be valued at lost profit suffered by the incumbent when access is transferred to the new entrant.

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

Commission's Views

The Commission is not in favour of pursuing the Delta Electricity proposal for similar reasons to those set out in its 2006 pricing decision and reiterated above. In particular, while it is true that the output of new generators may cause congestion in certain parts of the network, it is not the case that generators' locational decisions themselves cause new transmission investment to be required or undertaken. There is presently no obligation, of which the Commission is aware, on TNSPs to augment their networks simply to relieve congestion. In fact, as noted in section 1.1.2, it is unlikely to be efficient for TNSPs to eliminate all congestion through transmission investment. The regulatory arrangements are intended to support transmission

[104] International Power, Loy Yang Marketing Management Co, Intergen (Australia) TRUenergy, AGL Hydro, Hydro Tasmania, and Flinders Power, Supplementary Submission On Barriers To Entry 23 November 2006.

investment where it is maximises net market benefits or minimises the costs of meeting reliability criteria. Therefore, it is unclear what efficiency purpose would be served by levying deep connection charges on generators.

In coming to this position, the Commission does not deny that the location of a new generator may impose costs on other participants. The Commission understands that new generators can increase congestion, which can lead to other generators facing dispatch risk and being constrained-off. However, as discussed in Chapter 4, the Commission does not consider that the historical and foreseeable extent of such outcomes is material in the context of the costs of substantially altering the existing market design. If and when congestion does become a material problem for the NEM, the Commission considers that wholesale market pricing options are likely to be more promising than transmission generator charging options. This is because wholesale pricing options directly address the implications of a generator's locational decision – congestion – whereas transmission charging options address an issue over which a potential generator has little control, being the TNSP's decision to invest in the network.

If at some point in the future, policy-makers expressed an interest in developing transmission charging options for managing congestion (such as the Delta Electricity proposal), the Commission considers that a number of in-principle and implementation matters would need to be resolved. In particular, some methodology would need to be developed to determine how the "default investment path" was determined, given that a new entrant would be asked to fund the difference between it and the cost of the actual investment. Furthermore, how would the size and type of investment resulting from the generators' locational decision be determined? Presumably, it would need to satisfy the Regulatory Test. However, this raises the question of why the costs of certain network investments that meet the Regulatory Test ought to be recovered from consumers (as at present), while the costs of other investments that also meet the Regulatory Test ought to be recovered from a new generator. The Commission considers that such a division would to some extent be arbitrary and would place those generators who benefited from the default investment path in a privileged position that it is not clear they should enjoy.

With respect to the Southern Generators' Proposal, the Commission notes the similarities between this and the CSC/CSP rollout option put forward by the LATIN Group (discussed in Chapter 4). Both options effectively provide existing generators with financial compensation for congestion. The CSC/CSP approach provides incumbent generators with compensation for the settlement price impacts of congestion in a locational pricing environment while the financial access rights approach provides incumbents with compensation for not being dispatched due to congestion. In either case, the Commission does not believe that the present materiality of congestion warrants such a substantial change to the market design.

Recommendation 10:

No amendments to the current transmission pricing Rules should be implemented in order to improve location signals on new generators.

While the Commission has concluded that changes to transmission pricing arrangements are not warranted at this stage as a means of improving the efficiency of congestion management, the Commission notes a potential future interaction between transmission pricing and its work on a National Planner. In its December 2006 Determination on transmission pricing the Commission raised the issue of inter-regional transmission charges, and the appropriateness going forward of continuing to establish such charges through inter-governmental negotiation. Given the policy intent of improving co-ordination of transmission investment across the NEM through the creation of a National Planner, it is likely that consideration will need to be given to appropriate transmission charging arrangements between regions. The Commission has written to the MCE to notify it of the possible consideration of inter-regional transmission pricing through the consultation process on a National Planner. A copy of this letter can be found on the AEMC website.[105]

[105] See www.aemc.gov.au.

This page has been intentionally left blank

8 Congestion management regime overview

8.1 Introduction

The Terms of Reference provided to the Commission by the MCE for this review had three component parts. The first part required the Commission to *identify and develop improved arrangements for managing financial and physical trading risks associated with material network congestion*[106]. The third part suggested that the AEMC should develop a constraint management regime to apply to material constraint issues until addressed through investment or regional boundary change.[107] The recommendations set out in Chapters 4 to 7 of this report represent the Commission's response to these matters.

The second part of the MCE's Terms of Reference required the Commission to

> "..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[108]."

The Commission has endeavoured to articulate the relationships between these sets of arrangements throughout its publications and, in particular, within this Draft Report. Nevertheless, the Commission considers that it would be worthwhile to summarise the inter-related strands of the broader CMR in this final Chapter. The following sections therefore seek to demonstrate how the specific proposals in this report complement the wider set of arrangements for congestion management in ways that improve the ability of market participants to manage the physical and financial trading risks associated with material network congestion.

The Commission has already made significant changes in a number of areas that relate directly to the managemen of congestion in the NEM. The August 2007 Rule Determination to abolish the Snowy Region resolved the sole material and enduring congestion issue in the NEM. The reforms to the regulation of transmission services, and the introduction of the Last Resort Planning Power, establish a framework form promoting efficient investment by transmission companies. The Draft Determination on a new process for Region change will result in substantial reforms to the process for handling change in the wholesale pricing arrangements in the presence of new, currently unforeseen, instances of material and enduring congestion. The recommendation in this Draft Report contribute to, and are consistent with, this wider, significant package of reform within the existing framework of the NEM.

106 CMR Terms of Reference, para 3.1.

107 CMR Terms of Reference para 3.2.

108 CMR Terms of Reference para 3.2.

8.2 Elements of a broader constraint management regime

As noted in Chapter 1 and in the Directions Paper, the matters considered within the CMR relate to both the arrangements available for participants to directly *manage* the trading risks of congestion, as well as the arrangements for reducing the actual prevailing *level* of congestion. As noted in the Directions Paper, lower levels of actual congestion should result in lower congestion-related trading risks for participants. Virtually all of the arrangements discussed in this report fall within one or both of these categories.

The arrangements that enable participants to manage the trading risks of congestion include three key sets of Rules:

- The Rules surrounding constraint formulation and information disclosure regarding the occurrence of constraints and outages;
- The Rules surrounding the degree of localised wholesale pricing, which can help to alleviate the dispatch risks faced by generators in particular; and
- The Rules surrounding risk management instruments, which help participants manage the basis risk of localised pricing and settlement.

The arrangements for reducing the prevailing level of congestion are based on improving transmission capability. As noted in both Chapters 2 and 7 of this Draft Report, capability is a function of both:

- Transmission element capacity, which is in turn based on technical criteria; and
- The way transmission elements are operated under different power system conditions.

The following sections summarise the Commission's observations on the relationships between the different elements of the overall CMR "package" including how its recommendations sit within this broader framework.

8.3 Arrangements for improved congestion management

A great deal of the Commission's attention in the CMR was focussed on how the existing Rules enable participants to manage the trading risks arising due to congestion and how these arrangements could be enhanced. Many of the Commission's recommendations can be placed in this category.

8.3.1 Constraint formulation and information disclosure

As noted in Chapter 6, the Commission considers that greater predictability and transparency about the way the NEM operates and the outcomes of the dispatch process could facilitate more efficient management of congestion by participants. The Commission considers that the areas where greater predictability and transparency are likely to be of most value to participants in managing congestion include:

- The approach to formulating constraints – the Commission has recommended that the obligation on NEMMCO to use fully co-optimised constraints in most situations be brought within the body of Chapter 3 of the Rules rather than remaining within a derogation in Chapter 8.[109] This should provide participants with a better understanding of how potential changes in system conditions are likely to influence the dispatch process going forward;

- The methodology and process for developing, invoking and revoking constraints under different circumstances – the Commission has recommended changes to the Rules to oblige NEMMCO to develop and operate within published guidelines in these areas.[110] This should give participants greater confidence in making operational decisions (such as bidding and contracting) to manage their physical and financial trading risks;

- Real-time information regarding the application, invocation and revocation of constraints – the Commission has recommended that NEMMCO be obliged to develop and publish information that assists participants to predict the nature and timing of events that are likely to lead to changes in constraints and dispatch; [111]and

- Information regarding the occurrence and materiality of mis-pricing caused by congestion – such information could inform participants' contracting and investment decisions and thereby assist constraint management in the longer term. The Commission has recommended that NEMMCO publish more detailed information in this area.[112]

The use, by NEMMCO, of alternative or additional constraints to manage counter-price flows between regions is discussed below under risk management arrangements.

8.3.2 Wholesale pricing arrangements

As discussed in Chapter 4, more localised wholesale spot market pricing and settlement can help alleviate mis-pricing and reduce participants' dispatch risks. There are a variety of ways to allow for more locational prices. The Commission, however, considers that changes to NEM pricing regions should continue to be the main vehicle through which the wholesale pricing arrangement support efficient congestion management over time.

A substantially reformed process for region change has recently been subject of a Draft Determination by the Commission. The approach set out in the Draft Determination establishes an application-led process based on forward-looking economic criteria. This will provide a flexible and robust means of identifying and

---

109 See Recommendation 6 in section 6.1.

110 See Recommendation 7 in section 6.2.2.1.

111 See Recommendation 8 in section 6.2.3.

112 See Recommendation 9 in section 6.3.

assessing region change as an efficient response to congestion. Therefore, to the extent congestion is material and enduring in the future, regional boundary change will be available to provide a means of overcoming participants' dispatch risks of congestion.

With respect to interim means of applying localised wholesale spot pricing arrangements, the Commission came to the view that the benefits of such arrangements would typically be exceeded by their likely costs.[113] This is partly because the Commission found limited evidence of congestion that was material, stable and predictable – congestion in the NEM outside existing regional boundaries and the Snowy region has tended to be both unpredictable and transient. This means that a process of identifying material congestion, understanding whether it was likely to persist beyond the very short term and introducing an interim pricing response prior to consideration of boundary change would be impracticable. Participants would be faced with considerable uncertainty regarding the manner in which congestion was to be treated and the duration of that treatment.

The Commission also considered that any interim localised pricing mechanism would need to be accompanied by instruments to enable participants to manage the greater basis risk they would face under more localised settlement arrangements. The Commission took the view that the development and allocation of such instruments would be extremely difficult and controversial. Such difficulties would, in the Commission's view, outweigh the benefits of any reduction in dispatch risks from introducing localised pricing arrangements, in light of the present materiality of congestion in the NEM. Clearly, if the materiality of congestion were to significantly rise in the future, policy-makers would need to give fresh consideration to more localised pricing options and complementary risk management instruments. The Commission notes that re-consideration of such a fundamental change to the existing NEM wholesale pricing arrangements would require resolution of the complex and significant implementation issues associated, in particular, with the specification and distribution of the requisite risk management instruments.

8.3.3 Risk management arrangements

As noted above and throughout this Draft Report, more localised pricing arrangements tend to result in a greater risk that a participant's spot market settlement price diverges from the price at which its financial contracts are settled. In other words, more localised pricing may increase basis risk. Without effective risk management instruments, this could lead to a reduced willingness on behalf of participants to contract with counterparties located elsewhere.

The previous section explained that the Commission was not presently recommending interim localised spot pricing arrangements. Regional boundary change would remain the principal pricing response to material and enduring congestion. Therefore, the key risk management priority of the Commission has been to improve the firmness of the existing IRSR instruments.

---

113 See Recommendation 1 in section 4.4.5 and Recommendation 2 in section 4.4.6.4.

In this context, the Commission has recommended:

- Changes to the availability of IRSR units, so that they can be acquired three years in advance rather than just the present one year;[114]

- Changes to the funding of negative settlement residues, so that they are funded by directly billing the importing region's TNSP;[115] and

- Changes to the way NEMMCO intervenes in dispatch to prevent or limit counter-price flows and changes to the way it recovers negative settlement residues from the market. In particular, the Commission has put forward a more relaxed threshold for 'clamping' counter-price flows where dispatch is likely to be efficient and the introduction of 'positive flow clamping' to firm-up IRSR units where counter-price flows are likely to be a result of inefficient dispatch.[116]

8.4 Arrangements for reducing the level of congestion

It follows from the previous discussion that changes to the incidence of congestion in the NEM can affect the magnitude of participants' trading risks of congestion. The incidence of congestion is, in turn, partly a function of transmission capability. Many of the arrangements for increasing transmission capability were or are being addressed in reviews or Rule change processes outside of the specific CMR process. In this Draft Report, the Commission has sought to articulate how these different strands of work relate to congestion and whether any further changes are warranted at the present time.

8.4.1 Transmission planning and investment

Under Chapter 5 of the Rules, TNSPs' augmentations are required to satisfy the Regulatory Test. The Regulatory Test is intended to ensure that only efficient network augmentation options are developed and that non-network alternatives are properly considered in the process of determining how congestion ought best be reduced. The Commission recently made Rules outlining principles for a revised Regulatory Test to help ensure these outcomes would be achieved.

The objectives of the Regulatory Test imply that network planning is closely inter-related to the regulation of TNSPs' revenues. This is because the determination of how much TNSPs can earn from the provision of prescribed transmission services will ultimately determine whether they have incentives to plan and invest in their networks in the desired manner. The Rules for the regulation of TNSPs' revenues, and recent changes resulting from the Commission's 2006 "Chapter 6" review are discussed below.

---

114 See Recommendation 5 in section 5.4.

115 See Recommendation 3 in section 5.3.2.2.

116 See Recommendation 4 in section 5.3.2.3.

In addition to an obligation to apply the Regulatory Test when undertaking augmentations, the Commission made a Rule in 2006 empowering it to oblige TNSPs to apply the Test in certain circumstances. The 'Last Resort Planning Power' was intended to ensure that TNSPs do not neglect to consider potentially worthwhile investments simply because they cannot be justified on the basis of meeting deterministic reliability criteria.

In a similar vein, the MCE has recently directed the Commission to conduct a review into the development of a National Transmission Planner. While considering the manifold issues involved in such a structural change to the NEM arrangements, this review should help clarify the respective roles of the Regulatory Test and LRPP in promoting the optimal nature and location of transmission investment going forward. This will then feed back into the development of transmission capability and the occurrence of congestion.

8.4.2 TNSP incentives

As noted above, transmission planning arrangements are closely related to transmission revenue regulation. This is because the form of regulation applied to TNSPs in the NEM is a building-block incentive-based regime, in which TNSPs are rewarded for making capital investments through the provision of a regulated return. Without such incentives, TNSPs cannot be expected to voluntarily identify and develop augmentation options that could increase transmission capability and help reduce the incidence of congestion. This means that the National Transmission Planner review must take account of the recent Rule changes implemented following the Commission's 2006 review of transmission revenue and pricing.

A key aspect of the Chapter 6 Rule changes was the introduction of principles for a service target performance incentive scheme, to be designed and implemented by the AER. The AER has operated a useful service standards regime for TNSPs for several years, which has put up to 1% of TNSPs' revenues at risk based on network element availability. The Commission's changes were aimed at achieving a greater focus on the provision of transmission service at times it is most valuable to the market and increasing the proportion of revenue at risk. This recognises the strong relationship between TNSPs' financial incentives and the trading risks of congestion experienced by participants. That said, the Commission appreciates that the practical implementation of this regime is likely to be far from straightforward and looks forward to the AER's response to this challenge.

Given the recent changes to the transmission revenue Rules, the fact that the NTP review is already underway and the ongoing work of the AER, the Commission was reluctant to make additional recommendations in this Draft Report concerning TNSP incentives for transmission capability.[117] However, there are some areas where some changes may be justified. These include:

- Provision of greater information on transmission capability – the Commission observed that a limiting factor on promoting efficient transmission service

[117] See Recommendation 10 in section 7.2.3.

incentives is a lack of clarity over the meaning and measurement of transmission capability. The Commission therefore raised as a question for stakeholders whether more disaggregated information on transmission capability was likely to be worthwhile. This could also improve the ability of participants to predict the likelihood and impact of congestion, in conjunction with the other recommendations for information disclosure discussed above; and

- Incentives for NSCS – the Commission also raised as a question whether the revenue arrangements encourage TNSPs to favour capital over non-capital options, such as the utilisation of network support and control services. This would go against the NEM objective and the Regulatory Test principles.

8.5 Conclusion

The Commission notes that a great deal of work has been undertaken since the commencement of the NEM with the aim of enhancing the efficiency and reliability of electricity supply to consumers. Many of these changes have had either a direct or incidental impact on the occurrence of transmission congestion or on the ability of participants to manage the trading risks of congestion. The Commission has sought to avoid either duplicating or ignoring this other work in putting together its recommendations and questions for stakeholders in this Draft Report. Rather, the Commission's recommendations seek to complement other work programs to deliver an overarching CMR package that attempts to move the market forward in accordance with the NEM Objective.

This page has been intentionally left blank