C Assessment of Congestion Management Regime elements

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

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

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

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

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

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

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

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

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

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

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118 This new process commences on 1 July 2008.

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

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

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

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

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

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

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

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

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

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

- network constraints would be "very rare".

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

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

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

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

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

C.2 Dispatch

C.2.1 Background

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

We considered the following specific issues:

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

C.2.2 Constraint equations: formulation, development, implementation

C.2.2.1 Background

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

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

C.2.2.2 Discussion

Formalising constraint formulation

Evolution of the fully co-optimised constraint formulation

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

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

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

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

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

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

Formalising constraint formulation in the Rules

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

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

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

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

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

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

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

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

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

An alternative constraint formulation for exceptional circumstances

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4. NEMMCO tests the constraint equation(s).

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

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

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

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

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

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

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

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

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

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

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

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

134 NEMMCO, Draft Report submission, p.5.

135 EUAA, Draft Report submission, p.26.

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

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

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

C.2.2.3 Final recommendations and implementation

Formalising constraint formulation

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

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

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

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

Implementation

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

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

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

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

Guidelines for developing, modifying and implementing constraint equations

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

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

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

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

Implementation

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

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

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

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

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

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

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

C.2.3 Physical intervention in the dispatch process

C.2.3.1 Background

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

C.2.3.2 Discussion

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

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

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

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

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

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

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

- An increased threshold will reduce uncertainty for participants around excessive intervention in dispatch and will allow, in more cases, efficient dispatch to continue by delaying intervention.

- The uncertainty for participants created by clamping can flow through to customers as higher energy prices.

- NEMMCO has indicated that it can manage the negative settlement residue liability based on a $100 000 clamping threshold.

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

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

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

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

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

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

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

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

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

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

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

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

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

144 NGF, Draft Report submission, p.7.

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

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

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

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

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

146 EUAA, Draft Report submission, p.21.

147 TRUenergy, Draft Report submission, p.2.

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

149 ERAA, Draft Report submission, p.4.

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

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

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

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

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

C.2.3.3 Final recommendations and implementation

We recommend that the Rules:

- allow NEMMCO to intervene in dispatch to manage the accumulation of negative settlement residues;

- require NEMMCO to publish its intervention policy, including the trigger level, in the Network Constraint Formulation Guidelines; and

- require the AEMC to commence a review in three years to consider the efficiency of NEMMCO's intervention policy for managing the accumulation of negative settlement residues, including the intervention threshold level. One of the aims of this review will be to assess the further need for such intervention, with the view to remove it if possible.

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

Implementation

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

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

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

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

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

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

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

C.2.4.1 Background

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

C.2.4.2 Discussion

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

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

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

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

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

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

The majority of submissions supported this recommendation.

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

C.2.4.3 Final recommendations and implementation

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

Implementation

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

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

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

C.3.1 Background

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

The relationship between transmission capability and congestion

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

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

Factors influencing network capability include:

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

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

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

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

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

- investing to increase the capacity of network elements;
- maintaining network elements to ensure they are capable of operating to their technical limits (i.e. at their capacities);
- scheduling network outages at times when the value of network capability is relatively low; and
- engaging in other activities, such as the procurement or provision of NSCS to enhance network capability (see section C.3.5 below).

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

The relationship between transmission pricing and congestion

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

Scope of AEMC recommendations and observations

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

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

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

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

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

We discuss these recommendations and observations in the following sections.

C.3.2 Transmission regulatory framework

C.3.2.1 Background

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

C.3.2.2 Description of the framework elements

Revenue

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

Prescribed Services

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

Service Incentives

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

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

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

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

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

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

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

Negotiated Services

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

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

158 No parameters apply to VENCorp.

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

Pricing

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

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

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

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

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

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

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

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

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

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

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

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

C.3.2.3 Discussion

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

168 EUAA, Draft Report submission, p.30.

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

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

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

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

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

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

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

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

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

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

C.3.2.4 Final observations

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

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

C.3.3 Network access

C.3.3.1 Background

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

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

C.3.3.2 Discussion

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C.3.3.3 Final recommendations and implementation

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

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

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

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

Implementation

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

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

The Network Augmentation Draft Rule is published in Appendix G.

C.3.4 Transmission investment planning

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

C.3.4.1 Background

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

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

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

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

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

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

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

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

- improved locational signals to generators;

- a stronger incentive framework for TNSPs; and

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

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

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

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

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

C.3.4.2 Discussion

National Transmission Planner

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

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

The NTP objective is to:

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

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

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

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

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

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

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

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

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

The NTP's modelling will reflect:

- key transmission capability issues, including forecast constraints, which require action to enlarge or to increase the capability of the NTFPs to transmit or distribute electricity; and
- options, include network and non-network options, which, in the NTP's reasonable opinion, have the technical capability of addressing the identified key capability issues across identified NTFPs.

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

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

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

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

Recommending a new Regulatory Test

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

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

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

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

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

Measures of transmission capability

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

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

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

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

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

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

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

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

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

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

[190] Delta Electricity, supplementary submission, Congestion Management Review, 9 November 2006.
[191] NEMMCO, Draft Report submission, pp.12-15.

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

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

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

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

Demand Side Participation Review

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

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

The Stage 1 Final Report recommended that:

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

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192 TEC, Draft Report submission, p.2.

193 NEMMCO, Draft Report submission, p.12.

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

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

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

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

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

C.3.4.3 Final observations

The number of related reforms currently underway will significantly improve the transmission investment planning arrangements. The NTP will introduce a more co-ordinated approach for developing the NEM's transmission network over time. The NTNDP's strategic focus will provide participants with information to promote efficient investment decision making, further informed by forward-looking information about network capability and congestion.

The RIT-T will assist TNSPs to identify the preferred option that will provide the greatest economic benefits (present value), while continuing to meet the relevant reliability standards. Importantly, it will improve the incentive framework for considering alternative, non-network solutions (including demand side solutions). In addition, the LRPP provides a "safety net", to only be exercised as a "last resort".

Having progressed our consideration in these inter-related matters and reviews in a co-ordinated integrated manner, this combined package of reforms will provide a robust investment planning framework going forward. We do not consider there are any specific recommendations we can make in the context of this Review that would add value to the reforms currently being pursued as part of the NTP review, in particular.

C.3.5 Network support and control services

The previous section discussed, transmission capability at any given point in time depends on a number of factors. One such factor is the provision of NSCS. NSCS are those services procured and delivered by TNSPs or NEMMCO for the purpose of managing network flows to ensure secure and reliable operation of the power system or to enhance capability and thereby delivering a market benefit.

[196] NERA, DSP Review Stage 1 Final Report, p.45.

C.3.5.1 Background

The NSCS currently procured and delivered include:

- **Network Support Services** – procured by TNSPs via contracts with third parties (network support agreements (NSAs)), e.g. generators or load agreeing to be constrained-on (or off) in specified circumstances;

- **Network Control Ancillary Services** (NCAS) – procured by NEMMCO via contracts with Market Participants (not TNSPs) as either reactive power ancillary service (RPAS) in the form of voltage control, or network loading control ancillary service (NLCAS) e.g. rapid generator unit loading or load tripping scheme.

In addition, TNSPs can deliver some forms of network control services from their own infrastructure, such as reactive power capability from capacitor banks or static var compensators. The provision of such services can obviate the need for agreements to be struck with market participants. Appendix E provides further detail on the provision of NSCS.

Under the Rules, NEMMCO has the ability to procure NCAS as a means of ensuring sufficient capability to support meeting the power system security and reliability standards under the Rules. NEMMCO may also procure NCAS to assist in maximising the value of spot market trading. The costs of these services are recovered as part of NEMMCO's market fees (i.e. through general charges across the whole market). TNSPs are prohibited from submitting tenders to NEMMCO for the provision of NCAS above and beyond the levels required by jurisdiction-specific security and reliability requirements can affect the effectiveness of the current arrangements. TNSPs may use NSCS, however, to meet their reliability obligations under the Rules, jurisdictional requirements, or other service levels negotiated with individual connecting parties in connection agreements.

C.3.5.2 Discussion

The efficient procurement and delivery of NSCS is a component part of an efficient congestion management regime, although it is important to recognise the wider purposes of NSCS, e.g. in terms of system security and reliability. The development of more sophisticated measures of transmission capability will provide greater visibility on whether and how NSCS can be used to support more efficient congestion management – and refined incentive schemes can be used to reward TNSPs for the efficient use of NSCS-type solutions to the problem of delivering valued transmission capability from a congestion management perspective.

There are, however, two additional issues relating to the provision of NSCS where we wish to make observations. The first issue concerns the revenue treatment of NSCS solutions for TNSPs. The second issues concerns the status of a planned review by NEMMCO of NSCS arrangements, required under the Rules.

Revenue treatment of NSCS for TNSPs

As noted above, the efficient delivery of transmission capability by TNSPs requires consideration of all possible options for providing transmission capability. NCSC is one such option. The revenue treatment of network investment under the Regulatory Test has been the subject of detailed revenue, and a robust incentive-based approach has been developed. In contrast, where a TNSP adopts a non-network solution, the costs may be "passed through" to customers as if the cost of the non-network option were part of the TNSP's operating and maintenance costs.

We noted in the Draft Report that network solutions consequently provide a TNSP with the scope to earn a greater return than non-network solutions. This was because of the ability of TNSPs to earn a regulated rate of return on their network capital expenditure, while only being able to pass-through operating expenditures (within which most NSCS would be recovered) at cost. However, we continued, network capital expenditures also carried a risk that the TNSP will earn a reduced return if costs are over-run during that regulatory period. A non-network solution may therefore represent a lower risk/lower return option for a TNSP.

The Electricity Transmission Network Owners Forum (ETNOF)[197] disagreed with this last observation, however.[198] It stated that an TNSP remained legally responsibly for the ability to deliver network services, particularly reliability outcomes. Generation based non-network solutions have inherently lower availability than network solutions, increasing the risk of successful delivery of transmission services. There is a risk that a market counter-party may not meet its contractual obligation, possibly interrupting electricity supply. This potentially carried with it a greater risk than a network solution.

There are risks associated with providing transmission capability using both network and non-network solutions. These risks are understandably different. One depends on a piece of equipment operating as designed while the other relies counter-party meeting a contractual obligation, which in its commercial interest. ETNOF supported further development of incentive arrangements that would recognise the different risk profiles of network and non-network solutions. However, no submission provided any suggestions as to how the Rules could equalise a TNSP's financial incentives between network and non-network solutions.

Stage 2 of our DSP Review is considering this issue. It is looking into how the Rules promote financial incentives for TNSPs when investigating network and non-network options.

NEMMCO's review of NCAS

As noted above, NEMMCO and TNSPs both have some scope for using NSCS under the Rules. There is a degree of ambiguity over where the boundary of respective responsibilities lies and the extent of any obligation on TNSPs to consider NSCS in

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[197] ETNOF is now known as "Grid Australia".

[198] ETNOF, Draft Report submission, Congestion Management Review, 3 December 2007, p. 3.

undertaking network planning and/or applying the Regulatory Test. In practice, the current regime could be characterised as NEMMCO acting as "NSCS procurer of last resort". Further ambiguity lies in the appropriate approach for assessing NSCS options against conventional network investment options.

The more efficient use of NSCS as a means of providing transmission capability and changes to TNSP incentives will, over time, contribute to this outcome. However, it is not obvious that the current Rules concerning the roles and responsibilities for NSCS create barriers to this outcome. In any event, NSCS serve a number of purposes, some of which are only very indirectly related to the issue of congestion management.

Hence, while the question of roles and responsibilities for NSCS contracts is clearly an important issue for the operation of the NEM, it would appear to involve issues wider in scope than this Review. These issues should be considered through a separate and more focussed review.

Rule 3.1.4 (a1) of the Rules requires NEMMCO to review and report on the operation and efficiency of spot market for market ancillary services within the overall central dispatch and on the provision of NSCS. Given the possibility of NEMMCO's NSCS review overlapping with the considerations of this Review, NEMMCO sought and received the AEMC's agreement to delay the commencement of its NSCS review until after we published this Review's Draft Report.

We recommended in the Draft Report that NEMMCO should recommence its NSCS review. Accordingly, NEMMCO published a Draft Scoping Paper on a "Review of Network Support & Control Services" in March 2008.[199] In its NSCS review, NEMMCO proposes to cover five areas including: NSCS procurement responsibility and cost recovery; substitutability of NSCS; barriers to market entry of NSCS providers; use and deployment of NSCS; and types of NSCS markets.

NEMMCO released its Final Scoping Paper and finalised the scope of the NSCS Review in early June 2008.[200]

In the context of NEMMCO's NSCS review, the DSP Review Stage 1 Final Report recommended that:

- the AEMC request NEMMCO consider how technical requirements may be modified better to facilitate DSP as a means of providing NCAS as part of its current review of NSCS; and
- the roles and responsibilities for the provision of NSCS between NEMMCO and TNSPs be clarified to ensure that DSP is facilitated.[201]

[199] NEMMCO, "Review of Network Support & Control Services: Draft Scoping Paper", 6 March 2008. Available: http://www.nemmco.com.au/ancillary_services/168-0089.htm.

[200] NEMMCO, "Review of Network Support & Control Services: Final Scoping Paper", 2 June 2008. Available: http://www.nemmco.com.au/powersystemops/168-0097.pdf.

We consider that both components to this recommendation are already included in NEMMCO's NSCS review. NEMMCO is specifically looking at NSCS procurement responsibility.

It is also looking at barriers to market entry of NSCS providers. In its Final Scoping Paper, NEMMCO noted that the ability for parties to participate in tenders for service provision depend on, amongst other things, operational and technical requirements of requested services. These factors can create barriers to entry into the NCAS market.[202] To the extent DSP is restricted by technical requirements, we consider that NEMMCO's review would identify whether there are any possible modifications to facilitate DSP as a means of providing NCAS.

The Reliability Panel is currently undertaking a review of the technical standards in the NEM. This review is looking at the system standards (S5.1a), network performance standards (S5.1), generator access (S5.2), customer access (S.5.3) and MNSPs (S5.3a).[203] We consider that NEMMCO could inform this Reliability Panel review to the extent that its NSCS review identifies possible technical requirements that limit the provision of NCAS from DSP.[204]

C.3.5.3 Final observations

We note that NEMMCO is progressing its review on NSCS. We agree that the scope of the review will cover the key issues around efficient and effective delivery of NSCS in the NEM. We have written to NEMMCO to bring to its attention the final recommendation in DSP Review Stage 1 Final Report about possible technical requirements restricting facilitation of DSP as a NCAS. To the extent NEMMCO identifies technical limitations during its NSCS review, it can inform the Reliability Panel's concurrent review on technical standards.

NEMMCO's current review timetable seeks to release a draft determination report by the end of July 2008. It then intends to publish a Final Determination Report by the end of October. NEMMCO plans to submit to us proposed Rule changes to give effect to its recommendations in its Final Determination Report by the end of 2008.[205]

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201 NERA, DSP Review Stage 1 Final Report, p.47.

202 NEMMCO, Review of Network Support and Control Services: Final Scoping Paper, 2 June 2008, p.17.

203 AEMC 2008, Reliability Panel Technical Standards Review, Issues Paper, 9 May 2008, Sydney, p.9.

204 The letter we wrote to NEMMCO on this issue is available on the DSP Project Page on our website: www.aemc.gov.au.

205 See NEMMCO website for further information on the review timetable: http://www.nemmco.com.au/ancillary_services/168-0089.htm.

C.4 Risk management instruments

Congestion can give rise to both physical (dispatch) and financial (basis) trading risks. In the Terms of Reference for this Review, we were asked to identify and develop improved arrangements for managing both these kinds of trading risk (as they arise from congestion). This section discusses the management of financial risk. Improvements to the management of physical risk are discussed in section C.2.

C.4.1 Background

In the NEM's regional market within a region there is no price separation, and therefore no basis risk. But generators, large users and retailers contracting across regions do face basis risk.[206] To manage this inter-regional risk, participants make use of financial contracts such as capacity swaps. They can also purchase units to the inter-regional settlement residues (IRSRs) that arise when electricity flows between regions and those regions' prices differ.[207] These IRSR units help fund any hedging contract payment shortfall that arises from inter-regional prices differences.

NEMMCO sells IRSR units every quarter at the Settlement Residue Auction (SRA). At the SRA, auction participants can bid for units up to one year in advance. There are units for every regulated interconnector in the NEM, in both directions. This enables participants to hedge price differences between almost all regions, in both directions.[208]

As discussed in Appendix A, dispatch can sometimes result in "counter-price" flows (i.e. flows from a higher-priced region to a lower-priced region), resulting in negative settlement residues. The current mechanism for funding these negative settlement residues has the effect of reducing the value of IRSR units as an inter-regional hedging instrument: within a billing week negative settlement residues are offset against positive settlement residues for the same directional interconnector. This reduces the availability of positive residues that can be distributed to unit holders.

If there are any remaining negative settlement residues after the netting off, they are recovered from SRA proceeds from the same directional interconnector. SRA proceeds are what participants pay for IRSR units. The importing region's TNSP then receives these proceeds to offset transmission charges. These funding arrangements for funding negative settlement residues can affect the "firmness" of IRSR units as a mechanism for managing inter-regional trading risk.

In this section, we discuss ways in which congestion affects participants' ability to manage their financial inter-regional trading risk. We then discuss and recommend ways to improve the existing hedging instruments to help manage that financial risk.

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[206] We discuss the relationship between wholesale pricing granularity and basis risk in section C.5.

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

[208] Tasmania is connected to the NEM by Basslink, which is a MNSP. Because Basslink is not regulated, there no IRSRs attributed to flows between Tasmania and Victoria.

C.4.2 Improving existing risk management instruments

C.4.2.1 Background

Tools currently available to manage inter-regional basis risk

IRSR units

IRSR units are one of the key tools for assisting participants to manage basis risk in the NEM. IRSR units are a form of Financial Transmission Rights (FTR), and they are auctioned in advance through quarterly (SRAs). [209]

Broadly speaking, the IRSR units associated with a particular "directional interconnector" provide the holder with a share of the positive stream of payments or "residues", equal to the price difference between the two regions joined by the interconnector (in the direction of the directional interconnector) multiplied by the flow on the interconnector (when the flow is in the direction of the directional interconnector). Each IRSR unit relates to a notional 1 MW of the nominal flow limit of the corresponding directional interconnector. For example, if the nominal flow limit on an interconnector is 1000 MW, 1000 IRSR units would be auctioned and the holder of ten IRSR units would receive a flow of payments equal to one per cent of the residues described above.

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

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

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

- The flow on a directional interconnector might jointly depend on the output of particular individual generators which make use of the same parts of the network—they are, in effect, competing over a limited amount of capacity. When price separation occurs, the level of interconnector flow would depend on the

[209] FTRs are discussed in more detail in section C.5.

output of these generators (which in turn depends on generator bidding behaviour).

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

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

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

Box C.3: Causes of counter-price flows

There are several reasons why a dispatch might cause an interconnector to flow in a counter-price direction:

- Islanding – where a part of the network is physically separated from the rest of the network so that power cannot flow between the two and a counter-price flow is required to support a load in a separate region within the "island". In this case a counter-price flow is likely to be efficient, because the alternative would be load-shedding and a potential exacerbation of the islanding problem.
- Network loops – where a network loop exists that crosses a region boundary such that, by definition, flows along one section of the loop will be in the "right" direction and flows along another section of the loop will be counter-price. The abolition of the Snowy region, which takes effect on 1 July 2008, will remove the most significant inter-regional loop in the NEM.
- Interaction between direct current (DC) and alternating current (AC) interconnectors crossing the same region boundary.
- FCAS constraints – optimising energy and FCAS can result in a counter-price flow, but is likely to be of limited materiality.
- "Dis-orderly" bidding – where a single constraint involves an interconnector flow and a number of individual generators, and those generators are dislocated from the setting of their RRP but are seeking to maximise output at the prevailing regional price. In these circumstance, the generators may bid in a dis-orderly way (e.g. -$1 000/MWh), which in turn might be sufficient to back-off the interconnector flow to such an extent that it flows in a counter-price direction.
- The 5/30 Issue – rapid changes to power flows within a 30-minute trading interval.

Other tools

Participants also make use of financial contracts such as capacity swaps to manage inter-regional risk. This Review has not considered the specific financial contracts available for managing inter-regional risk, as we believe the design of financial contracts is best left to participants in financial markets. However, we do consider the liquidity of financial markets in all our decisions, and we note that participants generally consider financial market liquidity to be adequate in all regions but South Australia.[210]

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

C.4.2.2 Discussion

In the Directions Paper we invited views on risk management issues in the NEM. We considered submissions and engaged in bilateral discussions with stakeholders in order to understand better their views on whether and how risk management tools could be improved.

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

It was clear that the lack of firmness provided by IRSR units could reduce parties' willingness to trade inter-regionally and thereby detract from the liquidity of contract markets, in terms of volumes of contracts and numbers of contracting parties. Though very difficult to quantify the impacts of increasing IRSR firmness on inter-regional trade, it was reasonable to infer that improvements to the effectiveness of the hedging instruments would lead to greater inter-regional trading.

Against this background, we considered measures to firm up IRSR units and to improve the design of the SRAs.

Firming up IRSR units

We assessed three broad approaches to firming up IRSR units and therefore improving them as an inter-regional hedging instrument:

- improving the reliability and predictability of the underlying network;
- amending the arrangements for *managing* negative settlement residues; and
- amending the arrangements for *funding* negative settlement residues.

Improving the reliability and predictability of the transmission network

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

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

Many improvements have recently been made or are in the process of being implemented that should improve the reliability and predictability of interconnector transfer capability. These include the Chapter 6A Transmission Revenue and Pricing Review, the LRPP, the new process and economic criteria for region change and the Rule Determination to abolish the Snowy region.

In addition, the AER has developed the "Service Target Performance Scheme" designed to provide incentives for TNSPs that relate directly to increasing the provision of transmission capability at times when it has most value to the market, i.e. when constraints are binding. This work is focused on improving the incentives for TNSPs in how they manage and schedule network outages. We discuss this scheme in more detail in section C.3. The importance of this work is supported by our findings that the incidence of outage-caused constraints is increasing (see Appendix B). This scheme will potentially make an important contribution to the firmness of IRSRs.

There are also several prospective measures that might influence the provision of inter-regional transfer capability, and by extension the firmness of IRSR units. The most significant of these measures is the direction we received from the MCE to develop a framework for a NTP. In our Draft Report we recommend that the NTP will have responsibility for reporting on network capability as part of it NTNDP, which will provide an additional information resource for participants. We discuss this in more detail in section C.3.4.

This package of recent and ongoing reforms are likely to significantly improve the reliability and predictability of interconnector transfer limits. This combined with the recommendations in this Review to make more transparent predictable NEMMCO's process for invoking and revoking constraints (see dispatch) and to develop a Congestion Information Resource that will give participants more information to help them understand how the network's available network capability may change due to planned network events like outages.

Managing negative settlement residues

The firmness of IRSR units can be reduced by negative settlement residues. Negative settlement residues occur when constraints bind in such a way that: (a) there is a price separation, and (b) a flow on a directional interconnector is in a counter-price direction.

There are two separate effects at work. First, at times of counter-price flows, positive residues are not accumulating on the directional interconnector from the lower-priced to the higher-priced region. Second, positive residues that would otherwise be payable to holders of units in the directional interconnector going the other way, may be used to fund the negative residues (in the same billing week). Hence, the IRSR units may be made less firm in both directions of an interconnector by a single incident of negative residues accumulating.

NEMMCO currently manages the accumulation of negative settlement residues by "clamping" or restricting flows between regions, to limit the accumulation. We discuss this in more detail on section C.2.

Funding negative settlement residues

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

- If there are positive residues on the same directional interconnector in the same billing week as the negative residues, the positive residues are used to net-off the negative residues.
- Any negative residues that remain after netting-off within the billing week, are funded from the proceeds of the next auction(s) for that directional interconnector.

When we made the Rule[211] on 30 March 2006 enabling negative residues to be funded from auction proceeds, we included a three-year sunset clause in order to clearly signal our intention that this was not to be a long-term response to the negative settlement residue issue. Instead, our intention was always to examine the issue more thoroughly in the context of this Congestion Management Review.

In the Draft Report we proposed three options for improving the funding of negative settlement residues and asked for participants' feedback on them:

- netting-off against positive residues in the same billing week;
- directly billing the importing region's TNSP; and
- using an external source of funds, namely generators.

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

Box C.4: Netting-off against positive residues in the same billing week

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

The difference between netting-off and explicit recovery from auction fees is that the latter approach recovers the shortfall from future auction fees, while netting-off in effect increases the auction fee paid by the current holders of IRSR units. Allowing negative settlement residues to reduce the value of currently-held IRSR units would tend, other things being equal, to reduce the value of IRSR units for hedging purposes. This would presumably be reflected in the prices participants are willing to pay for IRSR units in the SRAs. Given that the "importing" TNSPs' load customers are ultimately the beneficiaries of both SRA fees and proceeds from lower TUOS charges, they would therefore ultimately incur the cost of funding negative residues irrespective of which of the two ways this occurred.

A majority of submissions to the Draft Report supported this recommendation.[212] ERAA and Macquarie Generation said it would increase certainty of the residues and enhance the SRA process.[213] They also considered it would reduce the risk of inter-regional hedging and increase competition in the various forward contracts in the NEM. Macquarie Generation also stated that the increased interest in IRSR units could contribute to higher auction proceeds to fund negative settlement residues.[214] NEMMCO said it could implement this recommendation by modifying its Market Management System.[215]

The EUAA did not support the recommendation. It preferred to retain the current arrangements, which have only been in place for the last 18 months, until the full impact of those changes was known.[216]

[212] CS Energy, Draft Report submission, pp.1-2.; NGF, Draft Report submission, pp.6-7; TRUenergy Draft Report submission, p.2; Origin Energy Draft Report submission, p.1; Hydro Tasmania Draft Report submission p.2.

[213] ERAA Draft Report submission, p.3; Macquarie Generation Draft Report submission, p.2.

[214] Macquarie Generation Draft Report submission, p.2.

[215] NEMMCO Draft Report submission, p.1.

[216] EUAA Draft Report submission, p.20.

Box C.5: Directly billing the importing region's TNSP

The question of whether it is appropriate for an importing region's customers to be entitled to SRA proceeds is a matter that was touched on but not addressed in our review of transmission pricing arrangements in 2006[217]; we considered it a matter requiring jurisdictional advice. It appears reasonable however, for negative settlement residues to be recovered from the importing region's TNSP. This is because loads in an importing region can benefit from the counter-price flow that led to the negative settlement residues in the first place, in that the counter-price flows may have led to a lower RRP in the importing region than would otherwise have been the case. This is consistent with the existing practice of recovering net negative Settlement residues from the importing regions SRA proceeds. In this context, an alternative to recovering negative settlement residues from SRA proceeds may be for NEMMCO to charge the importing region's TNSP for them directly. This could improve the transparency and certainty of the recovery process. We also note that, from a practical perspective, a mechanism for NEMMCO to charge negative settlement residues to a TNSP exists under the Rules already—the mechanism relates to instances when IRSR units are unsold.

Box C.6: Using an external source of funds, namely generators and "positive flow clamping" (PFC)

We assessed these options, discussing them in detail at a workshop in January 2008, but decided against recommending them for implementation as part of this Review. For a full discussion on these alternatives, see section C.4.4.

In the Draft Report, we recommended that negative settlement residues (a) should no longer be netted-off against positive residues within a billing week, and (b) should be funded by directly billing the importing region's TNSP.

We asked stakeholders for their views on this recommendation, in particular from TNSPs as to whether it raises any issues for the price-setting and revenue recovery procedures under Chapter 6A of the Rules.

The majority of submissions supported the recommendation. CS Energy, Origin Energy, Hydro Tasmania, Stanwell, Tarong Energy, InterGen, and the NGF all considered these recommendations would improve the firmness of IRSR units, which would therefore enhance their value as an inter-regional trading instrument. The EUAA supported the proposal in principle, but wanted more information. It

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

emphasised that the recovery of negative residues should be carefully aligned with the offset of settlement residues.[218]

NEMMCO sought further information about implementation.[219] ETNOF drew attention to the possibility that TNSP funding negative settlement residues could lead to volatility in transmission charges; transmission charges would need to take account of the transfers of settlement residues and auction proceeds.[220]

Macquarie Generation disagreed with the second part of the recommendation, arguing that it should be the *exporting* TNSP that funds negative residues caused by dis-orderly bidding, and suggesting that this would act as an incentive for TNSPs to address the underlying congestion problem.[221] It supported the first part of the recommendation.

These recommendations all seek to improve the usefulness of the IRSR unit as a hedging instrument for generators, retailers and large users. The first recommendation to change the funding of negative settlement residues will remove the potential for the value of IRSR units to be diluted because of incidents of negative settlement residues. It will also remove an arbitrary distinction in the Rules between funding negative settlement residue which occur in the same billing week as positive settlement residues, and those which do not. By removing this intra-week netting off, unit holders will retain the full value of residues accumulated during other events during a week, improving the IRSR as a risk management instrument.

Directly billing the relevant TNSP, who will then recover these costs through charges to its customers, is a more direct and transparent way to recover negative settlement residue than via auction proceeds, as is currently the practice – although the net impact is broadly the same. This arrangement provides NEMMCO with the flexibility to recover negative settlement residues in a timely manner rather than being limited by the timing of auctions every quarter.

These changes, coupled with an increase in the dispatch intervention threshold to manage the accumulation of negative settlement residues, will improve the value and usefulness of the IRSR unit as a mechanism for managing inter-regional basis risk, while also noting that it will increase transmission charges to customers. The net effect to customers is not known.

SRA design

We also considered incremental improvements to SRA design, to improve their flexibility and hence their usefulness. Options included longer- and shorter-dated IRSR units, peak and off-peak IRSR units, and the sale of some units further in advance.

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[218] EUAA Draft Report submission, p.20.

[219] NEMMCO, Draft Report submission, p.2.

[220] ETNOF Draft Report submission, p.5.

[221] Macquarie Generation submission, p.3.

We considered that the option to sell units further in advance had merit. The benefits of the other options obtained by repackaging the existing SRA product, would be done by market participants themselves or by financial intermediaries.

In the Draft Report, we therefore recommended extending from 12 to 36 months the lead-time between when the IRSR units are auctioned and when they apply. In other words, participants will be able to buy some IRSR units up to three years in advance rather than only one year in advance. Furthermore, we considered the Settlement Residue Committee (SRC) would be the most appropriate group to determine the size of each tranche of units available for auction. but we would expect that the majority of units will still be reserved for the nearer-term auctions.

Auctioning some IRSR units further in advance should make them more useful to participants who are seeking to plan and hedge their longer-term contract positions. It will provide further options for participants when structuring their long-term portfolio, and for secondary trading. We note also that there will be negligible downsides to implementing this proposal: implementation costs will be minimal; and any units that are available for sale three years in advance but are not sold, will be made available in the nearer-term auctions.

The majority of submissions to the Draft Report supported this recommendation.[222] EUAA noted that it would assist in the active management of basis risk, increase the flexibility for retailers to align contract term and price with minimal implementation costs, and support long-term portfolio management.[223] Two submissions commented that it would increase market liquidity of electricity derivatives.[224] Macquarie Generation stated that it would allow participants to develop further financial products in the secondary IRSR market.[225] CS Energy noted that it would improve price discovery of IRSRs and complement the current liquid period of vanilla contracts.[226] There was also support for the recommendation that the Settlement Residue Committee should determine the specifics of this proposal.[227]

On the other hand, ETNOF was concerned if selling units three years out would also require TNSPs to forecast events, like outages, that could affect interconnector capability three years out also. ETNOF stated such long term forecasting to poor forecasting with almost arbitrary assumptions.[228] Moreover, CS Energy noted that

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222 ERAA, Draft Report submission, p.3; Macquarie Generation, Draft Report submission, p.4; Snowy Hydro, Draft Report submission, p.2; EUAA, Draft Report submission, p.23; CS Energy, Draft Report submission, p.3; InterGen, Stanwell and Tarong, Draft Report submission, p.2; Origin Energy, Draft Report submission, p.1.

223 EUAA Draft Report submission, pp.3, 23.

224 Snowy Hydro, Draft Report submission, p.2; InterGen, Stanwell and Tarong Energy, Draft Report submission, p.2.

225 Macquarie Generation, Draft Report submission, p.4.

226 CS Energy, Draft Report submission, p.3.

227 Hydro Tasmania, Draft Report submission, p.2.

228 ETNOF, Draft Report submission, p.4.

IRSRs projected further into the future have uncertain value, and therefore proposed that the volume of IRSRs auctioned be weighted to the near term.[229]

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

C.4.2.3 Final recommendations and implementation

Our final recommendations affirm the draft recommendations. That is, we propose to improve the arrangements for managing and funding negative settlement residues, and to improve the design of the IRSR unit and of the SRA at which the IRSR units are sold. These recommendations will improve the firmness and usefulness of IRSR units as an inter-regional hedging instrument.

We are also recommending changes to the way NEMMCO intervenes in dispatch to prevent or limit counter-price flows including improving the predictability and transparency of NEMMCO's intervention and increasing the intervention threshold from $6 000 to $100 000. See section C.2 for more information on these recommendations and their implementation.

Firming up IRSR units

We propose amending the Rules to change how negative settlement residues are funded, we recommend that all negative settlement residues should be recovered directly from the importing region's TNSP.

Implementation

This new recovery method replaces NEMMCO's current practice of netting-off negative settlement residues against positive settlement residues within a billing week (Method 1) and then recovering any outstanding negative settlement residues from SRA proceeds (Method 2). Therefore, the *Draft National Electricity Amendment (Negative Inter-regional Settlements Residue Amounts) Rule 2008* (Negative Residue Draft Rule) deletes both Method 1 and Method 2 from the Rules and replaces them with this new recovery method (clause 3.6.5(a)(4)).

In a submission to our Exposure Draft[230], NEMMCO expressed concern that it may not have sufficient funds to finalise settlement should a TNSP be late with or not make payment to cover outstanding negative settlement residues. To address this, clause 3.6.5(a)(4) of the Negative Residue Draft Rule now allows NEMMCO to determine a different payment interval for the recovery of negative settlement

[229] CS Energy, Draft Report submission, p.3.

[230] NEMMCO, Exposure Draft submission, 15 April 2008.

residues from a TNSP in order to recover funds in advance of the normal settlement day.

NEMMCO also stated that in some circumstances it may be difficult to determine who is the appropriate TNSP in each region to be responsible for the payment of negative settlement residues. We recognise that this may be a problem and have amended the Negative Residue Draft Rule to ensure that this is resolved. Clause 3.6.5(a)(4B) of the draft Rule now provides the AER with the power to make (and amend) a determination on this issue. We consider the AER is the appropriate body to do this, given that it sets the TNSP revenue determination and therefore has all the necessary information to determine which TNSPs' customers benefit from negative settlement residues.

Should there be any unrecovered negative settlement residues at the time of the proposed Negative Residue Draft Rule's commencement, a savings and transitional provision enables NEMMCO to recover those residues using the method in operation at the time the residues were incurred, i.e. Method 2.

The current arrangement with inter-regional TUOS (which is due to expire on 1 January 2009) is unaffected by the new method.

SRA design

We recommend making several tranches of IRSR units available for auction up to three years in advance of the relevant IRSR quarter, with the SRC detailing the release profile of the units.

Implementation

This will be a change to the process of auctioning units under the SRA.

There are three key steps to implement this recommendation. The first is for the SRC to agree on the designs of units for auction three years out. The second is Rules consultation on the ammended Settlement Residue Auction Rules. The third is Software development in the SRA engine and interface.

Clause 3.18.3(a) of the Rules requires NEMMCO to develop "auction rules", which must include the procedures for conducting auctions and the timing of auctions.[231] Clause 3.18.3(d) enables NEMMCO to amend the auction rules at any time with the approval of the SRC. Clauses 13.8.3(e) and (f) identify the consultation process for amending the auction rules.

The process of extending the auctioning of IRSR units out three years is a procedural matter for NEMMCO and the SRC to consider. As such, and following discissions with NEMMCO, no amendment to the Rules is necessary to implement this change.

[231] The Auction Rules, and additional information on the SRA, are available on NEMMCO's website at: http://www.nemmco.com.au/settlements/settlements.htm.

In considering the recommendation, the SRC should have regard to submissions made to this Review's Draft Report. In particular, it should consult with participants on how it should auction off the new tranches of units. For example, should it decide to auction an equal number of units each quarter or should it gradually offer more units as the auctions get closer to the relevant quarter?[232]

On a related matter, NEMMCO identified that in June 2008, it will start auctioning units for Q3 2009 (July- September 2009). The current negative settlement residue recovery mechanism is due to expire on 30 June 2009. In our view it would be inefficient to consider reverting to the old recovery mechanism of auction fees when we are recommending a variation of the existing recovery mechanism. Therefore, it would be appropriate to extend the current sunset until the recommended recovery mechanism could be implemented. This would promote a smooth transition between the current and recommended new recovery mechanism. We could give effect to this in the form of a savings and transitional provision in the related Rule on funding of negative residues discussed above.

C.4.3 Negative settlement residues: alternative funding arrangements

Two options for improving the funding of negative settlement residues were proposed in the Draft Report which, after assessing, we decided not to develop as firm recommendations for change in the context of this Review:

- positive flow clamping; and
- generator funding.

In light of the PFC workshop held in January 2008 (discussed below), we have further considered the Gatekeeper and CS Energy generator funding options. The following sections present these option and discuss our view on these alternatives.

C.4.3.1 Positive Flow Clamping

This section considers PFC as an alternative to "zero flow clamping" in cases where binding constraints create incentives for generators to bid in a dis-orderly manner, resulting in counter-price flows. PFC works by clamping the relevant interconnector to a positive flow (in the direction of the lower priced region to the higher priced region), rather than clamping to zero flow as is the current practice. The main benefit of PFC compared with conventional clamping is that positive IRSRs continue to accumulate following the intervention, thus improving the firmness of IRSR units.

The concept of PFC was raised in a generic manner in the Directions Paper, as an option that would confer priority to interconnector flows in the event of a constraint that limited both intra- and inter-regional flows. Both Macquarie Generation and Snowy Hydro supported this option. Macquarie Generation said that it would be possible to implement a discretionary constraint to fully restore interconnector flow

[232] CS Energy, Draft Report submission, p.5.

and ensure positive residues where pre-dispatch was showing likely counter-price flows caused by dis-orderly bidding behaviour. Another alternative would be to provide for a sharing of the available transmission capacity between "local remote" generation and interconnector flows based on some form of pro-rating. Macquarie Generation also considered that either a full interconnector priority option or some kind of a sharing approach would provide a sharper locational signal for new generation investment. Snowy Hydro advocated the same proposal as an alternative to a CSC/CSP or Constraint Based Residue (CBR) approach to managing congestion.[233] Snowy Hydro saw advantages in eliminating negative settlement residues (without clamping) and maximising the usefulness of IRSR units for inter-regional trading.

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

Through our Draft Report, we decided to explore the potential benefits (and implementation issues) of the PFC option further and therefore specified the following high-level framework to facilitate consultation:

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

- PFC would be invoked when negative residues caused by one of the defined constraints were forecast to accumulate to $6 000.

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

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

In the Draft Report we also made the following initial observations of the impact of PFC. A more detailed explanation of the proposed PFC design can be found in Appendix E.

Effect on IRSR firmness

We considered that PFC would improve the firmness of IRSR units relative to zero flow clamping. This is because under PFC, the interconnector would be constrained

233 These approaches are discussed in more detail in section C.5.

at a non-zero level in the positively priced direction, which would result in the accumulation of IRSRs, whereas under the current clamping regime, no IRSRs accumulate.

Firming-up IRSR units would, other things being equal, encourage more participants to use this product to hedge basis risk (as opposed to using the IRSR product for speculative purposes). This could promote inter-regional contract trading, although it is difficult to assess the likely magnitude of this impact. IRSR units would still not be fully-firm and the returns would still be unpredictable due to other factors influencing the flow at which the interconnector constrains, such as generator behaviour and variations in transmission capability. The question is thus by how much PFC would improve firmness and to what extent would it enhance inter-regional trade.

Effect on dispatch

PFC would result in a different dispatch outcome to the current clamping regime. Intra-regional generators[234] would be backed off to a greater extent, while inter-regional generators would generate more.

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

System security

We do not believe that PFC would create issues for the management of system security. PFC and clamping both involve NEMMCO retaining the same level of control over the same variables in the dispatch. Hence, both would appear consistent with the secure operation of the power system. Neither intervention would be invoked if to do so would compromise system security. PFC and clamping would be discretionary interventions for NEMMCO to apply under the Rules (subject to consultation, publication and compliance with appropriate guidelines).

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

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

Dynamic efficiency effects

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

- create incentives for more efficient generator locational decisions; and
- create incentives for affected generators to find innovative ways, possibly in conjunction with TNSPs, to reduce the frequency and duration of constraints leading to negative settlement residues.

Financial market competition and liquidity

While PFC should increase the willingness of generators to enter contracts with counter-parties in other regions, it may, by increasing dispatch risk, reduce the willingness of generators to enter contracts within their own regions. Analytically, it is difficult to say whether the volume of contracts offered in a given region would increase or decrease as a result of PFC. However, firmer IRSR units would, at the margin, improve the ability of parties from other regions to offer contracts at a particular RRN. Hence, the number of parties offering contracts at a particular RRN may increase.

Participants' responses

Submissions to the Draft report were generally unsupportive of the introduction of PFC. While few submissions supported the introduction of PFC as a means of instilling firmness in IRSRs, a number of submissions felt that further detailed work to investigate how it would be implemented was necessary[235]. In particular, the EUAA considered that while PFC may be beneficial, further work was necessary to consider its impact on dispatch efficiency and IRSR firmness. However, Macquarie Generation recognised that a PFC approach would provide locational signals for generation investment and would create incentives for TNSPs and generators to work together to reduce intra-regional congestion.[236]

Most submissions were concerned about the choice of clamping threshold.[237] The choice of a fixed threshold would be arbitrary and many participants agreed with the concerns about this option that were noted in the Draft Report. A dynamically determined threshold would mean that it was not predictable and would therefore increase uncertainty. Submissions also noted that the outcomes of the dispatch process would potentially be more complex and unpredictable.[238] Some submissions argued that it would increase both the cost of generation and

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[235] Snowy Hydro, Draft Report submission, p.2, EUAA, Draft Report submission, p.22, Macquarie Generation, Draft Report submission, p.4, NEMMCO, Draft Report submission, p.1.

[236] Macquarie Generation, Draft Report submission, p.4.

[237] ERAA, Draft Report submission, p.4, CS Energy, Draft Report submission, pp.2-3, TRUenergy, Draft Report submission, pp.4-5.

[238] Snowy Hydro, Draft Report submission, p.2, Origin Energy, Draft Report submission, p.1.

transmission losses.[239] These submissions thought that PFC would lead to inefficient dispatch and would not materially increase market liquidity. Concerns were raised that PFC might create perverse incentives for generators and increase technical complexity into the dispatch process.[240]

NEMMCO considered that PFC seemed unable to be applied proportionately to changing market conditions. NEMMCO was also concerned about the implied underlying assumption that when a particular constraint binds, that it will always result in non-cost reflective bidding. [241]

The Stanwell, Tarong and InterGen submission considered that introducing PFC is likely to result in a reduction of dispatch efficiency with limited benefits with respect to market liquidity. They do not recommend the adoption of PFC and consider that the Draft report recommendations relating to risk management should be further developed. These generators based their analysis on work commissioned by EnergyEdge Consulting.

The EnergyEdge report provided an assessment of PFC as a means of reducing negative settlement residues, firming up IRSR units and increasing competition and market liquidity. EnergyEdge conducted a high level historical analysis using QNI residues as a case study. It found that PFC was unlikely to impact materially upon the risk profile of an IRSR unit.[242] Its results showed that PFC will only resolve a small portion of the basis risk with IRSR units and is not expected to result in any material change in the level of inter-regional trading by those entities. It therefore concluded that PFC will not have a material impact on market liquidity.[243]

EnergyEdge stated that the three-year SRA process, allocation of negative settlement residues to TNSP and reforms to improve reliability and predictability of interconnector transfer limits would deliver greater benefits for market liquidity, with less direct intervention in the physical market, compared to the introduction of PFC. Energy Edge stated that these arrangements improved risk management tools, transparency and predictability without the need for physical intervention.[244]

A larger group of generators[245] engaged ROAM consulting to conduct further analysis. ROAM conducted market simulations and detailed load-flow modelling to understand the market and efficiency impacts of PFC. Its analysis found that the application of PFC would lead to decreases in market efficiency. ROAM found that

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239 InterGen, Stanwell and Tarong Energy, Draft Report submission, p.3, CS Energy, Draft Report submission, p.2.

240 ERAA, Draft Report submission, p.4.

241 NEMMCO, Draft Report submission, p.3.

242 Energy Edge 'Positive Flow Clamping Review', p.5.

243 Energy Edge 'Positive Flow Clamping Review' p.51.

244 Energy Edge 'Positive Flow Clamping Review', p.5.

245 CS Energy Ltd, InterGen Australia, NewGen Power, Stanwell Corporation Ltd and Tarong Energy Ltd.

PFC would result in an increase in transmission system loss and total generation costs. These, in turn, would lead to an increased market pool price. [246]

The NGF, in contrast, was opposed to using any form of clamping as a solution. Its view was that the most efficient way to address negative settlement residues is to allow the market to operate without clamping. The NGF stated that the most appropriate response is to separate the funding and market dispatch issue. It proposed that funding negative settlement residues through uplifts to either wholesale or transmission prices, or charged to generators.[247]

C.4.4 Generator funding of negative settlement residues

We discussed this option in the Draft Report. This funding option supplements the accumulated residues payable to IRSR unit holders using with an additional source of funding. Externally funding negative settlement residues is a limited form of firming up the IRSRs. The principle could be applied more extensively, at the extreme by making IRSRs 100 per cent firm by funding any shortfall due to network limitations or negative settlement residue through some form of customer uplift. While this would substantially reduce inter-regional trading risk, we think that the cost to customers would be prohibitive and would represent a major policy change to how the NEM operates. We did not, therefore, develop the option any further in the Draft Report than in the Directions Paper.

The exception to this position relates to our observations around the possibility of Rule-based arrangements in which individual generators or groups of generators elect fund negative settlement residues themselves as a means of avoiding NEMMCO clamping interconnector flows. The CS Energy proposal discussed below in section C.4.4.4 is a form of this option.

An example drawn from Southern Queensland illustrates this type of arrangement. Under the current Rules, generators in Southern Queensland face the risk of being constrained-off through clamping when there are negative residues. This can occur even where they may be the least-cost plant to serve load in NSW. This can occur when the Tarong constraint (within Queensland) binds, the RRP is relatively high, and the Southern Queensland generators submit low-priced bids in an attempt to be dispatched. This can result in the interconnector could be dispatched in a counter-price direction.

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

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[246] ROAM Consulting 'Investigation of Positive Flow Clamping' p.17.

[247] NGF, Draft Report submission, p.7.

as firm as they would be under clamping, but would avoid the need for a physical intervention in the dispatch.

In our view, there were substantial implementation issues to resolve in developing the detail of such an option given that it is a form of location-specific congestion pricing (see section C.5 for a discussion on these implementation issues). We therefore questioned whether such an intervention was warranted given the materiality of the issue potentially being addressed. On the other hand, we could see its potential merit if it could be implemented in a transparent and non-discriminatory manner, and if it obviated the need for physical interventions in dispatch, having regard to the views of market participants on the undesirable effects of clamping. In the Draft Report we therefore sought views from stakeholders as to whether such a proposal was practical and/or warranted.

Participants' responses

Views were split as to whether generators ought to fund negative settlement residues. ERAA supported the proposal in principle but required further detail.[248] Origin Energy supported participant funding of negative residues but only as a "second-best" approach.[249] The benefit of this approach over clamping, Origin Energy considered, was that it would reduce the risk to generators caught behind temporary constraints. ERAA suggested that funds from generators bidding negatively behind a constraint could be used to fund negative residues caused by their dispatch.[250] TRUenergy also had no objections to generators voluntarily funding negative residues to avert zero clamping. While recognising the unlikelihood of such an arrangement arising, TRUenergy proposed that generators could arrange a bilateral agreement with NEMMCO.[251]

EUAA did not support the proposal for generators to fund negative settlement residues, arguing that it could be administratively complex, may lead to gaming, and may lead to inconsistency across the market.[252] Hydro Tasmania also rejected the proposal on the grounds that it was not clear how the set of eligible generators would be defined or whether it would force non-optimal NEMDE outcomes on all regulated interconnectors.[253]

CS Energy indicated their support for this proposal, provided that the Rules are simple.[254]

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[248] ERAA, Draft Report submission, p.3.

[249] Origin Energy, Draft Report submission, p.3.

[250] ERAA, Draft Report submission, p.3.

[251] TRUenergy, Draft Report submission, p.2.

[252] EUAA, Draft Report submission, p.21.

[253] Hydro Tasmania, Draft Report submission, p.3.

[254] CS Energy, Draft Report submission, p.3.

C.4.4.2 Positive Flow Clamping Workshop

We held a Positive Flow Clamping workshop in January 2007 to discuss in more detail PFC and the other funding alternatives.[255] This section discusses the views expressed at the workshop on PFC and presents our reasoning not to consider the option further in the context of this Review. In the following sections, we consider the participant alternatives also discussed at the workshop, and present our considerations on those alternatives.

Issues with PFC

At the workshop, participants expanded on the issues raised in their Draft Report submissions. These are discussed above in section C.4.3.1.

One particular issue raised at the workshop was the level of intervention and discretion required by NEMMCO. NEMMCO noted some of the difficulties that it may have when implementing PFC. It expressed concern that it may be required to either make a judgement about a participant's costs and bidding strategies, or to make a judgement when classifying pre-defined constraints. Other participants were also concerned that NEMMCO may need to exercise greater discretion than is presently the case on the timing and extent of the intervention.

Considerations

We discuss the benefits of PFC above in section C.4.3.1. In summary, we see PFC as an option for improving the firmness of IRSR units relative to their firmness under zero flow clamping.

However, PFC is only a partial solution. It only addresses the situation where negative settlement residues result from dis-orderly bidding. In addition, in the presence of strategic bidding, it is difficult to determine analytically what the dispatch efficiency benefits may be.

Importantly, PFC will increase the level of NEMMCO discretion in dispatch. One of the reasons zero flow clamping is a problem is because it requires NEMMCO use its discretion to intervene in dispatch. By increasing NEMMCO's level of discretion further, PFC is unlikely to improve market efficiency and might increase the general perception of dispatch risk.

For these reasons, we are not recommending PFC as an alternative to zero flow clamping in this Review.

At the PFC workshop two alternatives to PFC were introduced. TRUenergy suggested that we consider the Gatekeeper scheme, originally investigated by NEMMCO in 2003, while CS Energy proposed another option for the funding of negative residues by generators. While these provide an alternative to clamping that

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[255] For more information on the workshop, go to: "Positive Flow Clamping Workshop" http://www.aemc.gov.au/electricity.php?r=20080118.163655.

may reduce the level of intervention in the dispatch process, there are a number of design and implementation issues that would need to be considered in order to consider participant funding of negative settlement residues. The alternatives are discussed below.

C.4.4.3 Gatekeeper proposal

At the PFC workshop (and in its Draft Report submission) TRUenergy proposed the Gatekeeper scheme as an alternative to PFC. Gatekeeper was originally investigated by NEMMCO in 2003.[256]

Proposal objective

The objective of this option is to provide incentives for a "gatekeeper" generator to improve interconnector efficiency, thereby increasing the quality of IRSRs.

Proposal description

This proposal pre-defines the relative shares of access to a RRN held by an IRSR unit holder. This option allocates to a "negative gatekeeper" generator, a "natural volume", which is equal to the difference between the constraint limit and "k", where "k" is a selected "natural volume" of flow on the interconnector. If the generator produces electricity to a level that constrains the interconnector flow below "k", then the generator compensates IRSR unit holders, thereby removing the dis-orderly bidding incentives for the generator. Where the generator produces electricity to a level below their natural volume, the generator is rewarded with the additional settlement residue. The scheme also provides a form of "constrained-on" payment to "positive gatekeeper" generators, where increased generation increases an interconnector flow thereby increasing the quantity of settlement residue.

Benefits

TRUenergy identified a number of benefits from this scheme:

- there is no need for a constraint to be applied and there is therefore no need for involvement by NEMMCO and no unpredictability;
- optimal dispatch is guaranteed as generators are priced, at the margin, accurately to their coefficient in the constraint equation. Dis-orderly bidding is not rewarded;
- generators and holders of IRSR units know with certainty, in advance, what proportion their settlement will be relative to the various regional prices. It therefore increases the firmness of the IRSR units; and

[256] CRA, "Dealing with NEM Interconnector Congestion: A Conceptual Framework", 24 March 2003. A copy of this report can be found on the MCE website : www.mce.gov.au.

- while counter-price flows are possible, they are funded by the gatekeeper generators;

NEMMCO noted at the workshop that this option was likely to be simpler to implement than PFC because it was operationally similar to the trialled CSP/CSC mechanism in the Snowy region and would not rely on direct market intervention or discretion by NEMMCO.

Issues

There are a number of outstanding issues that would need to be considered in order to implement this alternative method for funding negative settlement residues:

- How would the proposal determine which generator is dispatched? It is suggested that this may be based on the generator's associated coefficient in the constraint, or proportionally on the generator's market share.

- What are the consequences of dispatch being on a 5-minute basis while settlement is on a 30-minute basis? Flows on interconnectors can sometimes change direction within a 30 minute period. If this happened, there would need to be a process for managing any disparities between the 5-minute dispatch and 30-minute settlement outcomes.

- How would the scheme address the need to balance a generator's dispatch amount, which is based on the actual generation, and the settlement amount, which is based on the generation that is sent out, accounting for transmission losses?

- How should incentives be set at the start, to ensure that there is no potential for oscillatory behaviour, i.e. when generators may bid their generation up in one interval and down in the next in order to find a balance between obtaining higher prices and being dispatched?

- What would happen if more than one constraint is binding at the same time?

- What would happen if an interconnector is involved in the constraint?

Considerations

The major benefit of this scheme would be that it would firm up IRSR units by eliminating the impact of gatekeeper generator behaviour on interconnector flows, and therefore on the IRSRs. For example, if a gatekeeper generator chose not to generate, thereby reducing interconnector flows, that generator would need to "supplement" the IRSR funds to compensate unit holders for forgone residues due to reduced interconnector flows. While the scheme also has positive benefits for dispatch efficiency by improving incentives for the gatekeeper generator, it is difficult to analytically determine the dispatch efficiency in the presence of strategic bidding more broadly.

Additionally, this proposal is for a NEM-wide change and therefore represents a substantial reform. In this Review, we have considered proposals for NEM-wide change in the context of the materiality of the congestion problem to date. The historical level of congestion at this stage has not been material enough to warrant NEM-wide solutions. Section C.5 discusses are reasoning for not pursuing NEM-wide solutions in more detail. We are therefore not recommending the gatekeeper alternative as a proportionate response or alternative to funding negative settlement residues at this time.

C.4.4.4 CS Energy generator funding of negative residues proposal

At the PFC workshop CS Energy presented an option in which generators would fund negative settlement residues arising on an interconnector.

Proposal objective

This proposal would increase the firmness of IRSRs relative to zero flow clamping by having generators elect to fund the negative settlement residues that accrue in absence of NEMMCO clamping interconnector flows.

Proposal description

In this option NEMMCO would calculate and publish information in real time, identifying what proportion of the negative settlement residues each generator would be responsible for, given its current level of generation. This option would not affect NEMDE dispatch. Generators would face the decision to either fund the corresponding negative residues or change their output levels. Generators would be allocated a share of flow through the constraint to their RRN in proportion to available generation and fund negative residues for generation in excess of their share.

Benefits

According to CS Energy, there are a number of benefits from this proposal. It considers that the proposal:

- would not affect NEMDE dispatch and could therefore be implemented relatively easily;
- could be applied locally and preserves the current regional structure; it is therefore not a substantial reform to the NEM;
- need only apply to material constraints, which are determined by the market. The proposal would not require any NEMMCO discretion in the dispatch process; and
- would only include generators who elected to participate.

NEMMCO noted at the workshop that this option was also likely to be simpler to implement than PFC and would not rely on direct market intervention or discretion by NEMMCO.

Issues

In order to implement this alternative there are a number of issues to further consider:

- What are the consequences of the fact that generators would need to re-bid to manage their position?
- How would an event that requires the accumulation of negative residues for system security reasons be addressed? For example, there may be circumstances, such as an islanding event, where it is necessary for the flows to be counter-priced, in order to maintain system security and supply reliability.
- How would the scheme address the need to balance a generator's dispatch amount (which is based on the actual generation) and the settlement amount (which is based on the generation that is sent out) accounting for transmission losses?
- How would the scheme address those constraints that include more than one interconnector?

Considerations

This option has potentially the same main benefit as the Gatekeeper proposal. That is, it will increase the firmness of IRSRs. However, unlike the Gatekeeper proposal, this option is able to be applied selectively and is therefore a localised solution, not a NEM-wide one. Such a change could represent an incremental reform to the NEM. It also enables the market to judge what is a "material" problem and therefore whether or not to apply the scheme.

Given the benefits of this proposal, we support its continued development by its proponents as it focuses on addressing the impacts of clamping, which we identified as a problem. However, we recognise that there are a number of issues that require resolution. Should the proponents develop this option further, then it could be assessed in due course as a Rule change proposal.

C.5 Wholesale market pricing and settlement arrangements

C.5.1.1 Introduction

The manner in which congestion is priced in the wholesale market clearly has an important role to play in managing congestion. This section provides more detailed discussion and reasoning on whether changes should be made to the wholesale pricing and settlement arrangements to improve the management of congestion in NEM. The Terms of Reference for this Review highlighted, in particular, the need to examine mechanisms that could be introduced on a localised (i.e. in respect of a specific constraint) interim basis prior to congestion being addressed on an enduring basis through regional boundary change or through an investment response from transmission, generation or load. We considered the role for such mechanisms in conjunction with identifying and developing improved arrangements for managing financial and physical trading risks associated with material network congestion.

C.5.2 Background

Congestion can cause the marginal cost of electricity (based on bids and offers submitted) to vary across locations. To the extent these variations in the cost of electricity are reflected in prices, participants will face different types of incentives and risks. Price divergences reflecting network congestion can provide important economic market signals and may positively influence behaviour at both the operational (e.g. generator bidding) and investment (e.g. location and timing) levels.

Greater price granularity, which prices congestion explicitly, reduces the level of generator mis-pricing and physical (or dispatch) risk. It reduces the risk of being constrained-off (wanting to generate but not being allowed to) or constrained-on (not wanting to generate but having to). At the same time, it increases the price (or basis) risk that participants need to manage. More prices in the market means participants need to hedge a greater number of possible price differences that arise in the presence of congestion. Any change to the balance between priced and unpriced congestion therefore affects the balance of risks that market participants need to manage. Changes to the wholesale pricing and settlement arrangements therefore need to be considered alongside financial instruments used to manage any increase in the associated basis risk. Such changes are important defining characteristics of options for change.

There is a variety of ways to allow for more locational prices, but they fall into two broad classes of option for change in the NEM. The first is a location-specific, time-limited constraint mechanism which is applied in specific places exhibiting material congestion. The second is a NEM-wide change to the market wholesale pricing and settlement arrangements. This second category includes a range of options. At one end is the existing regional structure where congestion is priced between regions (i.e. across regional boundaries) but not within a region. Under this model, all generators within a region are settled at the RRP. At the other end of the spectrum are more extreme granular pricing options, like generator nodal pricing (GNP), where every generator is priced at its own node and congestion is reflected in each of those nodal prices.

In its *Statement on NEM Transmission* in May 2005, the MCE emphasised the importance of stability and predictability in a regional structure, saying that changes to regions should occur only if they deliver a net improvement to the efficient operation and investment environment of the market. These key principles provide an important framework that promotes region change as a means of addressing transmission congestion only when congestion is enduring and material and when there is a clear economic case for the change. This, in turn, can promote efficient investment options in transmission, generation and load to address congestion in the stages prior to considering a region change.

In December 2008, we made a Rule that implements a new process for region change from 1 July 2008.[257] This Rule introduces an application-based process to region change. The criteria for assessing a proposed region change require the AEMC to be satisfied that the solution will materially improve economic efficiency. This includes, but is not limited to: improvements in productive efficiency; efficiency in relation to the management of risk and the facilitation of forward contracting; and long-term dynamic efficiency.

This new process for region change is more open and transparent than the current process in rule 3.5 of the Rules. It facilitates better informed, more robust and accountable decision-making than under the previous Rule. It will also help ensure that any future new region boundaries will reflect "choke points" of material and enduring congestion, creating clear price incentives for the more efficient location of loads and use of electricity services.

In assessing how changes to the existing wholesale pricing and settlement arrangements could be used to manage congestion, we considered:

- the range of options for more granular wholesale pricing and settlement
- the appropriateness of constrained-on payments for generators; and
- information on mis-pricing that would give participants a way of identifying historical levels and locations of congestion.

We discuss these issues in the following sections.

C.5.3 Options for more granular wholesale pricing and settlement

In the Draft Report, we discussed incremental changes as well as fundamental reforms to the way congestion is priced in the NEM.

The *incremental change* was to amend pricing for constrained-on generation.

The options we classified as *fundamental reforms* to the NEM were:

- limited forms of nodal pricing;

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[257] *National Electricity Amendment (Process for Region Change) Rule 2007 No 11*. See AEMC 2007, Process for Region Change, Rule Determination, 20 December 2007, Sydney. Available: www.aemc.gov.au.

- CSP/CSC; and
- CBR.

We assessed these options carefully in the light of stakeholders' views, evidence on the incidence and materiality of congestion (see chapter 2 of the Final Report and Appendix B), and subsequent analytical work on the characteristics and practicalities of the different options. Importantly, all of these options, as well as the many variants and hybrids that exist, represent different ways of addressing the same core issues. We therefore developed a common analytical framework and terminology to explicate and to compare the options.

C.5.3.1 Analytical framework

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

Constraint prices

A constraint which binds imposes a cost on the market. This cost can be measured directly by calculating the reduction in the total cost of the dispatch (based on the bid prices submitted to the dispatch process) that would result if the binding constraint could be marginally relaxed. This can be interpreted as the "price" of the constraint. When a constraint does not bind, the total dispatch cost will be unaffected by relaxing the constraint limit slightly. Hence, a constraint only has a positive price when it binds.[258] A constraint price is specific to the dispatch interval in which it binds. If the same constraint binds in a different dispatch interval, then the constraint price may well be different.

Constraint prices can be used to calculate the extent to which a particular point on the network is "mis-priced" relative to its RRN.[259] If there are no binding constraints, then there will no mis-pricing.[260] If a constraint binds, then locations on

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

[259] For further discussion of mis-pricing and its potential economic consequences, see Appendix A.

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

the network represented by terms in the binding constraint equation will be mis-priced.

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

Generators are dispatched on the basis of the marginal cost of supply at each individual node, because this ensures that the total cost of the dispatch is minimised. However, each individual generator is settled at the RRP for the output they are dispatched at. Differences between the price at which a generator is dispatched and the price at which it is settled are the source of the risks of being constrained-on or constrained-off. This, in turn, creates incentives for dis-orderly bidding.

Constraint rents

A constraint which is binding indicates that transmission capability is a scarce resource to the market. The value of this scarce resource is equal to the volume of energy (in MWs) being constrained multiplied by the constraint price. This can be interpreted as a "rent" earned by the constraint when it binds. A rent is generated every time a constraint binds. How these rents are distributed, either implicitly through the dispatch process or explicitly through the sale or allocation of financial instruments, is a key feature that differentiates one constraint pricing mechanisms from another.

Financial instruments derived from congestion rents

Constraint rents are the building blocks of any arrangement that reflects network congestion in prices in the wholesale market. Congestion price risk can be characterised as parties being exposed to (i.e. required to fund) these rents when they occur. Financial instruments can be designed to help manage such price risk. The basic approach is to design a financial instrument to enable parties to buy a share in the congestion rents when they occur (and thereby hedge the risk). The two main approaches to designing such an instrument are to have either:

- an "unbundled right" to a share of congestion rents for each individual constraint equation involved in the congestion pricing scheme; or

- a "bundled right" to a share of congestion rents across a "bundle" of constraint equations (e.g. all the constraint equations involved in the congestion pricing scheme).

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

Methods of distributing congestion rents

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

- "auction" the rights;
- "negotiate" a distribution of rights, and "arbitrate" if no agreement can be reached; or
- "allocate" the rights in accordance with an administrative rule set when the localised pricing intervention is established.

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

Using the analytical framework to characterise different approaches

This section applies the analytical framework set out above to describe different approaches to congestion pricing, including the current NEM arrangements and options for reforming them.

Nodal markets

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

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

The NEM market design

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

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

When the definitions of the pricing regions change, so does the balance between (a) congestion that is explicitly priced and (b) the corresponding distribution of implicit financial instruments to hedge price risk within regions. This can be illustrated using our Final Rule Determination to abolish the Snowy Region.[261] This change:

- reduces the number of settlement prices (from six to five);

- reduces the number of hedging instruments (by abolishing the IRSRs between Victoria and Snowy and between New South Wales and Snowy, and by creating new IRSRs between New South Wales and Victoria); and

- retains the existing method of distributing IRSR units (through the Settlement Residues Auctions) and distributing intra-regional "implicit FTRs" (matched to the dispatch)—with Murray now receiving an implicit FTR providing settlement at the Victoria RRP, and Tumut now receiving an implicit FTR providing settlement at the New South Wales RRP.

Using the analytical framework to characterise potential changes to the NEM design

Several options for pricing congestion in the NEM (listed at the start of section C.5.3) were discussed in our Directions Paper. These included options that might

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

potentially be invoked on a localised, time-limited basis in response to specific congestion issues.

All the options involve a degree of localised spot market pricing in an attempt to overcome the mis-pricing problem. The key distinguishing feature between them is the manner in which rights to congestion rentals are "bundled". Here we characterise the different options in terms of this feature.

Bundled rights options

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

<u>CSP/CSC</u>

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

- A set of generators (and interconnectors) and a set of constraints is identified. For example, in the CSP/CSC Trial in the Snowy Region the scope of the pricing intervention was defined in terms of a list of around 130 individual constraint equations representing the flow limit between the Murray and Tumut nodes in the Snowy Region, and encompassed the generators (and interconnectors) involved in those constraint equations (i.e. Upper Tumut, Lower Tumut, Guthega, Murray, Snowy-NSW interconnector, and VIC-Snowy interconnector).[262]

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

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

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

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

- In addition, each interconnector in the scheme is entitled to congestion rents equal to the price difference between the two regions multiplied by a pre-specified volume of its flow (i.e. an explicit CSC volume).[263] These congestion rental payments to (or from) each exposed interconnector modify the net value of the IRSR fund, which comprises the bundle of all constraints that cause price differences between regions. The SRA process is then applied to the modified IRSR fund, with the auctioned products providing firmer hedging than under the status quo.

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

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

<u>LATIN Group proposal</u>[264]

The Latin Group in its response to this Review's Issues Paper, put forward a fully-developed CSP/CSC proposal. The proposal focussed on, among other things, the difficulties associated with identifying and implementing CSP/CSC on a localised, incremental basis. The solution identified in the proposal was to:

- apply CSC/CSP across the whole NEM;

- make a one-off allocation of CSCs (i.e. financial rights to be settled at the RRP) to all existing generators on the basis of a representative dispatch scenario – with CSCs being "non-firm" (i.e. scaled back to match available physical capability) and lasting for the duration of the associated generation asset;

- make automatic adjustments to the original allocations of CSCs in the event of extra network capacity being made available; and

- allocate CSCs to interconnector flows, as a means of firming up the IRSR units as a hedging instrument between RRNs and removing negative settlement residues.

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

<u>Other bundled options</u>

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.

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

264 LATIN Group, submission to AEMC Congestion Management Issues Paper, April 2006

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

"Unbundled rights options"

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

<u>Constraint-Based Residues (CBR)</u>

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

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

C.5.3.2 Discussion and assessment of options

We assessed the options discussed in the previous section against the Review's Terms of Reference and the National Electricity Objective. We used these criteria to develop an assessment framework based on the following inter-related factors:

- influence on bidding behaviour and dispatch efficiency;
- practicability and complexity of implementation;
- allocation of congestion rights and competition issues;
- predictability and regulatory risk; and
- proportionality of response.

Influence on bidding behaviour and dispatch efficiency

Addressing mis-pricing

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

In a market characterised by price-taking bidding behaviour, ensuring that settlement prices are consistent with the prices used in the dispatch process ought to promote the economic efficiency of dispatch. This is because participants' marginal decisions would be based on their local nodal price rather than the RRP. Generators will not have incentives to bid in a dis-orderly manner (e.g. -$1 000/MWh bids) if dispatch and settlement prices are aligned. Snowy Hydro, Origin Energy and ERAA saw merit in a constraint pricing mechanism, like CSP/CSC, as a transitory solution to congestion.[265]

However, where generators have some degree of market power, it is not possible to conclude on the basis of analytical reasoning alone whether more localised pricing arrangements would enhance economic efficiency. This is because generators with some influence over their local nodal price may seek either to withhold a proportion of their output or to offer it at a very high (non-cost-reflective) price in order to maximise their profits based on a price-volume trade-off. One manifestation of this behaviour might be a tendency for generators to leave some spare capacity or "headroom" on the transmission network between their location and higher-priced nodes. The absence of locational pricing may provide incentives to such generators to bid at or below their resource costs in order to be dispatched. They would not benefit from exercising any transient market power they have.

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

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

[265] Snowy Hydro, Draft Report submission, p.1; Origin Energy, Draft Report submission, pp.2-3; ERAA, Draft Report submission, p.2.

Impacts on hedging

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

There is a large number of constraints in the NEM which relate to technical limits on the combined behaviour of generators in a region and interconnector flows to that region (which in turn reflect the behaviour of generators in other regions); for example, situations where a limited amount of transmission capability is available across a set of generators, some of which are in a different region. The constraint might bind with low interconnector flow and high regional generator output, or high interconnector flow and low regional generator output.

Under the NEM settlement Rules, when the constraint binds at a low interconnector flow, a congestion rent is implicitly transferred from the relevant IRSR fund to the dispatched generators.[266] This process detracts from the use of IRSRs as a hedging instrument. Localised congestion pricing, in combination with the distribution of explicit rights to the resultant residues, can increase the firmness of the IRSRs.

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

However, "nodalising" the price for congested power stations has a dual impact for a business. Firstly, combining the possible lost quantity and lower unit price introduces a new form of intra-regional basis risk. Secondly, while the mechanism may improve dispatch in the physical market, it may be perceived as a retrograde step in the hedging market.[267]

Effect on longer term decisions

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

267 Babcock and Brown Power, Draft Report submission, p.2.

As discussed earlier, there are a range of locational signals present in the NEM under the current design and Rules. VENCorp noted a congestion pricing signal, like that provided by a constraint pricing mechanism may influence investment location decisions, where other factors are marginal.[268] However, we are not persuaded that a location-specific interim constraint management mechanism will strengthen or clarify these signals. This is because a location-specific interim constraint management mechanism is uncertain and temporary in application. Hence, the pricing outcomes that might result from its implementation are also uncertain. Prospective investors will not generally know whether (or how) a particular project will be affected by such a constraint management mechanism or not when they make decisions to invest (or dis-invest). It could also be argued that the uncertainty over whether a project will be priced regionally or locally (for an unspecified period of time) reduces the clarity of existing locational signals, by creating more regulatory "noise". Under either scenario, the possibility of a location-specific interim constraint management mechanism does not improve locational signals for investment.

In addition, a location-specific interim constraint management mechanism may also affect the ability for participants to access financing to invest. A location-specific interim constraint management mechanism, and the increased risk and uncertainty such a mechanism introduces to the market, will add to the uncertainty of power project financing. This may increase the cost of capital and therefore the costs for a new entrant.[269]

In general, we were persuaded that a location-specific interim mechanism would materially and positively influence the efficiency of investment decisions.

Practicability and complexity of implementation

This Review's Terms of Reference specifies that we must develop a constraint management mechanism for managing material congestion prior to its being addressed by investment or regional boundary change. Practicability and complexity of implementation are important considerations in determining what types of mechanism would be appropriate, when considering such mechanisms under our statutory duty to promote the National Electricity Objective.

A key implementation issue for a location-specific interim constraint management mechanism is the means of allocating rights to congestion rents (which afford protection from intra-regional price risk). This is discussed in detail in the following section. This section is restricted to other implementation questions around a location-specific interim constraint management.

The Draft Report highlighted some of the difficulties with the implementation of a location-specific interim constraint management mechanism, including:

- the threshold criteria and process for *introducing* a constraint pricing mechanism;

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268 VENCorp, Draft Report submission, p.2.

269 Babcock and Brown Power, Draft Report submission, p.5.

- the identity of the constraints to be "priced" as part of the regime; and
- the threshold criteria and process for *removing* a constraint pricing mechanism, given that it is intended to be an interim measure only.

While the trial of a CSP/CSC instrument at Tumut (the Snowy Trial[270]) tackled some of these issues, we do not believe that the implementation approach adopted for the Trial is easily applied to other settings.

While the Snowy Trial was a positive development for the market, in two specific ways, it represented a special case, possibly unique in the NEM.

- The underlying congestion problem was clearly identifiable, well understood, and unlikely to change in the short to medium term.
- Only one generation company (Snowy Hydro) and two plants it owned (Lower Tumut and Upper Tumut) were involved in the trial. This made it relatively straightforward for market participants to agree on an allocation of CSCs between the Snowy-NSW interconnector and Snowy Hydro's Upper and Lower Tumut generation plants because the level of interconnector flow with and without the output of these generators is simple to establish.[271]

The analysis undertaken for this Review on the incidence and materiality of congestion demonstrated that, apart from the Snowy region, congestion in system normal conditions have generally been relatively unpredictable and transitory. This accords with the views of a significant number of stakeholders provided at the Industry Leaders Forum on congestion[272], and more generally through engagement with stakeholders.[273] However, other stakeholders such as "the Group"[274] and the NGF contended that congestion is sufficiently material to warrant consideration of congestion pricing reforms.[275]

In its Draft Report submission, the Group stated that we did not assess either the costs or trading risks of implementing a location-specific interim constraint management mechanism and therefore could not determine a materiality threshold

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270 In the Snowy Trial, the intent was to enable Snowy Hydro's Tumut generation to be settled at its local nodal price for its marginal output when the Murray/Tumut constraint was binding. When flows through Snowy were in a northward direction, this would increase Tumut's incentive to generate at times of high NSW prices. When flows through Snowy were in a southward direction, this would reduce Tumut's incentive to generate and consequently reduce the likelihood of counter-price flows.

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

272 AEMC, Industry Leaders Forum – Summary of discussion. Available at www.aemc.gov.au.

273 Macquarie Generation, Draft Report submission, p.1; CS Energy, Draft Report submission, p.1.

274 The Group comprises of: LYMMCO, AGL Energy, International Power, Flinders Power, InterGen Australia, and Hydro Tasmania.

275 The Group, Draft Report submission, p.2; NGF Draft Report submission, p.2.

or net economic benefit to determine whether or not the NEM should have such a mechanism.[276] Hydro Tasmania agreed.[277]

This raises a critical practical issue for application of forms of localised pricing intervention. How is the need for the intervention identified sufficiently far in advance to allow managed and orderly design and implementation, if potential leading indicators (e.g. historic incidence of congestion) are not reliable?[278] While locations can be identified easily with the benefit of hindsight, it is not clear that they can be forecast accurately. This is a significant consideration given the importance of forward contracting in the NEM market design. To illustrate, there is anecdotal evidence from a range of stakeholders that the recent congestion issues involving the South Morang constraint in Victoria were not anticipated.

This suggests it is difficult to implement effectively a location-specific interim constraint management mechanism. There are a number of reasons for this. The first is difficult to design and effectively implement a mechanism that will work in all situations. While such a mechanism was introduced in the Snowy region, the unique characteristics of that situation make it highly unlikely that those conditions would arise anywhere else in the NEM.

Second, there is the question of what is an appropriate lead time for implementing such a mechanism. The evidence on prevalence indicated that congestion was relatively transient. This would mean in order for a mechanism to be of value, it would need to be implemented relatively quickly. However, given the volatile nature of the NEM's wholesale market, forward contracting is incredibly important. This would mean introducing a location-specific interim constraint management mechanism at short notice into an environment where most participants were already heavily contracted.

The MCE stated the importance of forward notice when it proposed a new process for region change. It recommended a minimum implementation lead time of three years.[279] The purpose of the proposed three-year lead time is to provide market participants with adequate time to adjust to the region change. The contracting implications of a location-specific interim constraint management mechanism are similar in nature to those associated with changing region boundaries. There is therefore a question as to why an interim mechanism should have a shorter notice period compared to a region change given market participants would need to amend their contracting positions to respond to its introduction.

If congestion pricing interventions were adopted in other circumstances, the evidence on the apparently transitory nature of congestion – and the lack of robust leading indicators - suggests two possible risks. First, that instances where a location-specific interim constraint management mechanism might improve the

[276] The Group, Draft Report submission, pp.2-3.

[277] Hydro Tasmania, Draft Report submission, p.4.

[278] EUAA, Draft Report submission, p.15.

[279] AEMC 2007, *Process for Region Change*, Final Rule Determination, 20 December 2007, Sydney.

efficiency of outcomes are missed. Second, that location-specific interim constraint management mechanisms are introduced where they deliver no benefit.

Allocation of congestion rights and competition issues

The question of how to allocate explicit congestion rights cannot easily be resolved. Some submissions to the Draft Report agreed that the allocation of transmission rights would be controversial and could create wealth transfers without efficiency improvements.[280]

The LATIN Group proposed one possible allocation method. It suggested that CSCs could be allocated to all existing generators on the basis of a representative dispatch scenario. This would have the advantage of ensuring that the timing and location of new investment in generation was based on future expected spot prices at the relevant location, rather than the proponent's expectation of being able to obtain financial settlement at the RRP by bidding in a dis-orderly manner.

In its Draft Report submission, Origin Energy proposed an allocation based on constrained capacity (or financial access to the constrained region's RRN) on the basis of the individual generator's capacity share in the overall generation capacity contesting a particular constraint. A share may also need to be allocated to an interconnector to ensure competitive neutrality. The fixed, but not firm, access would be allocated to existing generators only. New entrants would not change the allocation, and would only receive fixed access rights for any additional transmission capacity they fund.[281]

However, there are possibly detrimental impacts from allocating explicit congestion rights to incumbents in these ways.

The allocation of explicit rights based on historical dispatch would create its own implementation challenges. Put simply, what historical dispatch should be used? There are dispatch outcomes every five minutes all of which, it could be argued, are representative to a degree. Why would a generator accept one dispatch over another if the choice is arbitrary (within a range) and if it is disadvantaged by the choice? There would be no simple way to get agreement and reconcile differences. This would be a big challenge as there would be the potential risk of lengthy disputes.

In addition, an allocation method that provided existing generators with (potentially tradable) explicit rights in preference to prospective new entrants could be potentially viewed as discriminatory and anti-competitive. While this consideration was not relevant in the case of the Snowy Trial, it is a more pressing concern in most other settings in the NEM, where there are a number of competing generators potentially affected by the congestion that might be priced through a CSP-type

[280] CS Energy, Draft Report submission, p.1; Macquarie Generation, Draft Report submission, p.1; EUAA, Draft Report submission, p.14.

[281] Origin Energy, Draft Report submission, pp.2-3.

arrangement. Hydro Tasmania commented that rights were already allocated according to dispatch volumes and therefore we were overstating the problem.[282]

However, a change in the "allocation" through implementing a location-specific interim constraint management mechanism such as CSPs/CSCs can involve significant wealth transfers and represent material changes to the way in which the market operates over time. Consistent with good regulatory practice, such intervention should not be considered lightly and should only be used if they are effective and proportionate to the problem being addressed.

Alternatively, congestion rights may be allocated through an auction process. In theory, selling rights would ensure those participants who value the rights most would receive them, which would appear to be more consistent with non-discrimination and economic efficiency. However, to implement such a framework of periodic auction, for potentially a very large number of constraints, which would add greatly to the complexity of the NEM trading environment. This would represent a very large change to address an issue of apparently limited materiality based on historic evidence.

In addition, the nature of congestion rights is likely to change over time as constraint equations are altered to reflect transmission augmentation, changes to the provision of NSCS, new generation investment and load growth. Purchasers of explicit congestion rights would be faced with uncertainty over the value of their explicit rights in these circumstances. We recognise that participants currently have to deal with uncertainty over constraint equations and dispatch. However, currently participants have a degree of familiarity with the current arrangements and the Final Report recommendations on improving the transparency and information around constraint formulation and invocation should assist in this regard. The question is whether the selling of rights will make these changes less predictable.

Predictability and regulatory risk

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

Further, even if implementation of a location-specific interim constraint management mechanism were uncontentious amongst participants, the risk would remain that a mechanism could be implemented in circumstances where there proves to be no material congestion problem to address. In other words, it is possible that the implementation of a regime would be subject to "regulatory failure". While it could be contended that this risk is relatively small because the additional price risk will be minimal if there is no congestion, an alternative view is that the possibility of

282 Hydro Tasmania, Draft Report submission, pp.5-6.

inappropriate or poorly focused regulatory interventions in the pricing and settlement arrangements creates an additional form of regulatory risk. In addition, if there are several interim mechanisms in place, this could hinder the consideration and implementation of more effective policy responses. It may be more effective and efficient to consider a broader response to the localised congestion rather than continuing to address it on a location-specific interim basis.

Proportionality of response

The endorsement of a pricing approach to improve congestion management would, in our view, be a disproportionate response to the problem under examination, given:

- the evidence of limited material congestion in the NEM persisting beyond one or two years at any given location;
- the difficulty of predicting when and for how long congestion will occur;
- the temporary nature of any congestion management regime and the numerous implementation and allocation problems surrounding the provision of congestion rights for parties to hedge the resulting basis risk;
- the scope for investment or regional boundary change to address material and enduring congestion; and
- the ambiguity over whether locational pricing will actually improve the economic efficiency of dispatch in a market where parties have some degree of market power.

C.5.3.3 Final recommendations and observations

We do not recommend any change to the current wholesale pricing and settlement arrangements as a means of managing congestion over and above fixing the Snowy region and implementing the new Region Boundary change process. In particular, we have carefully considered the possible role of a location-specific interim constraint management mechanism and do not consider its implementation as a permanent fixture of this regulatory framework to be consistent with meeting the National Electricity Objective.

Introducing these sorts of changes to the wholesale pricing and settlement arrangements is undesirable because they would likely raise significant implementation issues and competition concerns, with significant wealth transfer implications. They constitute a disproportionate response to the problems creates by the present levels and impacts of congestion, based on the currently available evidence. Also, given the present levels of congestion are unpredictable and transitory, it is not possible to design a "one-size fits all" mechanism that can be triggered automatically. Such a mechanism, if deemed appropriate, would need to be designed and tailored for each individual circumstance. In addition, the extent of some of the possible NEM-wide changes may also go beyond the scope of the options identified in the Review's Terms of Reference.

While there is not currently a place for a location-specific interim constraint management mechanism or more granular pricing more generally in the NEM, the discussion in chapter 4 of the Review's Final Report raises the question of whether such options (and other wider-ranging reforms to the factors that generator locational signals) may be beneficial in the future. That chapter discusses what impact the climate change reform agenda may have on the NEM, and therefore whether there is a role for more granular pricing options in an environment, should the pattern and materiality of congestion look different then compared to now.

C.5.4 Assessment of pricing for constrained-on generation

We considered whether recommending a change to the pricing of constrained-on generators would be a beneficial incremental change to the NEM pricing and settlement arrangements.

C.5.4.1 Background

A generator is constrained-on if it is dispatched at a level of output above that which it is willing to supply at the prevailing RRP. This can occur because the dispatch process implemented by NEMDE aims to minimise the aggregate costs of serving load based on the marginal cost of supply at each node, while RRPs are calculated as the marginal cost of supply at the RRN. In the presence of congestion, the RRP and marginal cost of supply at different nodes may diverge. For example, a generator might be dispatched for a volume it is offering to supply at a price of $40, despite the RRP being only $30. In this example, the difference between Q_{30} and Q_{40} is the "constrained-on volume". This situation could arise if the generator's output helped relieve a constraint and thereby allowed cheaper generation from elsewhere to supply load at the RRN. Constrained-on generation is therefore a symptom of mis-pricing, which in turn is a feature of a regionally priced market design.

C.5.4.2 Discussion

The question raised in the Directions Paper was whether generators that are constrained-on ought to receive some form of compensation to reflect the difference between the price at which they would be willing to supply and the RRP they receive through the settlements process. Submissions expressed a range of views. Some supported constrained-on payments, questioning whether the absence of such payments was consistent, in principle, with an open, competitive market. Others expressed concerns about how such arrangements would be funded, and whether it was appropriate for constrained-on payments to be considered in isolation from other means of managing congestion.

Our recommendation in the Draft Report was *not* to implement a regime for constrained-on payments.

The current Rules

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

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

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

Different options for constrained-on payments

Congestion pricing based

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

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

There are two main issues with this type of arrangement. First, it creates short-term, but potentially very acute, pockets of temporal market power that would have to be dealt with. If a generator knew with certainty (as might be the case under certain outage conditions) that it would be constrained-on, it could set its own price for the amount of constrained-on output.[283] The NGF posed, however, that when generators receive a level of compensation based on their bid or spot price, "concerns about the potential for the misuse of market power should not be given preference over increased efficiency in dispatch or improved locational signals for investment".[284]

The potential abuse of localised market power can be dealt with effectively using contractual or regulatory means — such as minimising (or eliminating) the exposure of a participant with market power to its local price via the allocation of congestion rental rights, and/or by other contractual arrangements. Such approaches are often used in other electricity markets, where localised market power is an issue, and have been used in the NEM in restricting the allocation of IRSR units to Snowy Hydro. They do, however, add a new layer of regulatory intervention to the market design. Localised abuse of market power that is transparent and exercised over a relatively small customer base should be of much less concern that the less transparent abuse of market power over a large customer base. In contrast, the abuse of market power in large regions affects a greater number of customers, but is often masked and is therefore more difficult to detect and mitigate.[285],[286]

Second, this type of arrangement would require an external source of funding because it is a one-sided arrangement in which there are not reductions in settlement payments to constrained-off generators. Symmetric forms of congestion pricing, such as CSCs or CBR, are, by definition, revenue neutral – they redistribute existing rents If the scheme were not to be funded internally, through redistribution, then an external source of funding would be required, e.g. from higher charges to load customers.

Compensation based

An alternative method of implementing a form of constrained-on payments is through compensation payments from NEMMCO. This would, in effect, extend the scope of the approach adopted when a generator is constrained-on through NEMMCO direction to encompass all instances where generation is constrained-on. Many submissions to the Draft Report supported this approach.[287]

The NGF proposed a compensation scheme that involved generators electing one of two alternative compensation approaches: a short-run (or bid) price or a long-run (LRMC) price. If a generator selects the short-run approach, it would receive its bid price for each MWh sent out during a trading interval to relieve congestion. Under the long-run approach, every three to five years a generator would elect the method

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

284 NGF, Draft Report submission, p.4.

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

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

287 Macquarie Generation, Draft Report submission, p.2; Hydro Tasmania, Draft Report submission, p.2; ERAA, Draft Report submission, p.5.

for compensation. Under this second approach, a change would only be permitted under exception circumstances.[288]

Currently, the costs of NEMMCO compensation payments linked to directions are recovered through market fees. Extending the scope of these payments would increase market fees. An alternative approach would, for example, charge loads, e.g. by recycling costs via TUOS charges. These are both, in essence, forms of "uplift charge"

A compensation-based approach would address one potential concern relating to the exercise of temporal market power by generators, because it would limit the price paid to constrained-on generators through the administered rule for calculating compensation.

Economic impacts of constrained-on generation

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

Some stakeholders stated that the current mechanism for pricing and compensation through NEMMCO direction and negotiated compensation with TNSPs is inefficient because it is not commensurate to the risks of generation and costs cannot be sufficiently funded.[289] Similarly, some considered that subjecting generators to a NEMMCO direction is a second-best solution and an alternative pricing algorithm would be a better solution.[290]

The introduction of constrained-on payments would address one type of mis-pricing that can occur in the NEM. To this extent, it could reduce the incentives that might otherwise apply for constrained-on generators to manage dispatch risk by bidding in a dis-orderly manner or by understating the physical flexibility of plant for the purposes of dispatch.[291] In doing so, constrained-on payments could overcome one source of dispatch inefficiency and these generators would have one less risk to manage in making investment and operational decisions.

However, the expense of making constrained-on payments to generators would need to be funded by some external party. If the funding for a constrained-on payment scheme were met through a market levy (e.g. in a similar way to the recovery of NEMMCO costs), the expense would be incurred by the generality of market participants, in the absence of clearer method for allocating costs. If the cost were

[288] NGF, Draft Report submission, pp.4-5.

[289] Snowy Hydro, Draft Report submission, p.2.

[290] Hydro Tasmania, Draft Report submission, p.2.

[291] Macquarie Generation, Draft Report submission, p.2.

recovered through transmission charges, as proposed by the ERAA[292], then in effect the costs would be recovered from load in the relevant transmission areas in which the constrained-on generator was located.

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

A final economic impact of a constrained-on payments regime is the interaction between transmission and generation. One interpretation of constrained-on generation is that it provides support to the transmission network. The reason such generators are being required to run could be interpreted as reflecting a shortage of network capability. The Rules recognise this interaction and provide for contractual relationships between generators and TNSPs to be made under the provisions in Chapter 5 of the Rules. These could take the form of network support agreements. Imposing a constrained-on payments regime through the pricing and settlement arrangements might be viewed as pre-empting a transmission response. However, it might also be argued that a formalised constrained-on payment regime would give greater visibility to the absence of transmission responses, such as through contract or through investment, and might represent an additional discipline on TNSPs under a service incentive framework.

Materiality of constraining-on

Our general approach to this Review has been to assess potential changes to the existing arrangements in the light of the evidence on the materiality of the problem being addressed by potential change.

The evidence on materiality of congestion is summarised in chapter 2 of the Final Report and in Appendix B. The key observations in respect of constrained-on generation are as follows:

- for the three years from 2002/03 to 2005/06, there were on average around 40 connection points in the NEM that were constrained-on. This is about half the number of connection points that had been constrained-off;
- constrained-off generation was generally affected for a greater number of hours than constrained-on generation; and

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292 ERAA, Draft Report submission, p.5.

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

This evidence does not provide strong support for change. Some submissions to the Draft Report agreed there is minimal need for implementing constrained-on payments regime. CS Energy put forward that network service agreements negotiated with TNSPs provided a workable solution to issue.[293] The EUAA stated that generators already priced the risk of being constrained-on in their bids and offers and a constrained-on payment scheme would mean generators would be paid double for that risk.[294]

In addition, while stakeholders debated the risks of being constrained-on, no submission elaborated on how significant an issue it was. Therefore, we do not find a strong support for change to the current arrangements. This view is supported further by the lack of evidence to demonstrate that existing mechanisms for contractual arrangements between generators and TNSPs are not working effectively. Conversely, we are aware of some examples where contractual arrangements are being used in the context of network support. It is more appropriate, in our view, to let these existing channels work, rather than impose new arrangements that might “crowd out” existing arrangements.

C.5.4.3 Final recommendations and observations

We do not recommend implementing a regime of constrained-on payments through changes to the Rules on settlement of the spot market because it would not represent a proportionate means of improving the management of physical and financial trading risk from network congestion.

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

In addition, historically, the materiality evidence does not support a case for change. The evidence also suggests that the existing transmission responses are working effectively. We have not found a case supporting implementation of a constrained-on payment regime at this time.

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293 CS Energy, Draft Report submission, p.1.

294 EUAA, Draft Report submission, p.18.

C.5.5 Information on the incidence and patterns of mis-pricing

C.5.5.1 Background

As discussed above, mis-pricing arises in regionally priced and settled markets like the NEM in the presence of congestion. Information on the historical incidence of mis-pricing can help market participants understand and manage the risk implications of network congestion.

C.5.5.2 Discussion

While we do not consider there is a case for changing the NEM's wholesale pricing and settlement arrangements to manage congestion, there may be a case for change in the future. The establishment of an information source that identifies the level and location of historical mis-pricing will assist in the future assessment of the materiality of congestion.

Mis-pricing information will also be of value in identifying specific points of congestion, where targeted measures, like network support agreements, could be implemented to assist in the management of congestion. Mis-pricing information will assist participants in identifying areas where they themselves can negotiate such agreements.

Investors will also find value in mis-pricing information as a tool in their decision-making processes. While investment locational decisions are based on a range of factors including access to fuel and water and environmental considerations, access to transmission is also important. Information on mis-pricing will help inform investment location decisions, identifying possible congested areas and therefore prompting a comprehensive assessment of congestion at a preferred location.

The NTP will also make use of the mis-pricing information. In our Draft Report on the NTP, we recommended that the NTP should incorporate any recommendations made in relation to the collection and reporting of congestion related information in this Review. Further, the NTNDP should not be precluded from presenting other similar types of information such as that related to generator mis-pricing, which may be of value to participants in assessing current and future network capability. The historical mis-pricing information provided in the CIR will form a useful source for the NTP in preparing its annual NTNDP.

C.5.5.3 Final recommendations

We recommend amending the Rules to require NEMMCO to publish analysis on the extent and pattern of "mis-pricing" caused by congestion, and to update this analysis regularly. This information will form part of the recommended CIR.

Section C.6.4 presents a more detailed discussion on this recommendation, including stakeholder comments on the recommendation and its implementation.

C.6 Information

The ability of market participants to manage the physical and financial risks arising from network congestion depends in large part on the quantity, quality and timeliness of the information made available to them. Investors also need to be well informed in order to make efficient locational investment decisions for building new transmission and generation capacity—decisions which should contribute to reducing the prevalence of congestion in the longer term. As part of this Review, therefore, we have proposed several ways to improve the information resources available to market participants (and policy makers) on dispatch, risk management, and investment planning.

C.6.1 Background

The information currently published by NEMMCO and TNSPs to help market participants understand and manage congestion is as follows (references in square brackets are to clauses in the Rules):

Daily

- Market Management Systems/Market Data (published by NEMMCO): providing detailed information on constraints used in dispatch, as well as current and historical demand and market prices.

- Pre-dispatch schedule (published by NEMMCO): setting out forecast load, plant availability, peak demand and spot price for each trading interval (clause 3.8.20 of the Rules).

- Daily information (published by NEMMCO): setting out the previous day's market outcomes.

- Short Term Projected Assessment of System Adequacy (ST PASA) (published by NEMMCO): a seven-day forecast of system demand and supply conditions, including forecast plant and network outages and interconnector capability (clause 3.7.3).

Weekly

- Weekly Bulletin (published by NEMMCO): a summary of market outcomes from the previous week.

- Medium Term PASA (published by NEMMCO): a forecast of system conditions for a period of 24 months from the coming Sunday (clause 3.7.2).

Monthly, quarterly or *ad hoc*

- Planned Network Outage (PNO) information (published by TNSPs and NEMMCO): information published every month on the timing and nature of planned outages for the next 13 months and their projected impact on network transfer capabilities; also includes information on the likelihood that outage timing will vary (rule 3.7A).

- Network Outage Schedule (NOS) (published by NEMMCO): published every 4 hours, covering a shorter period than the PNO information.

- Large transmission network consultations (published ad hoc by TNSPs): details of proposed larger (>$10m) augmentations for stakeholder consultation (clause 5.6.6).

- Interconnector Quarterly Performance (published quarterly by NEMMCO): details of historical differences between interconnector capacity and transfer capabilities for each day in the previous quarter (clause 3.13.3(p)).

Annually

- Statement of Opportunities (SOO) (published by NEMMCO)—ten-year outlook of the demand/supply balance by region and NEM-wide (clauses 3.13.3(q-t)).

- Annual National Transmission Statement (ANTS, contained within the SOO) (published by NEMMCO)—setting out forecast utilisation of, and constraints on, national transmission flowpaths and the options that could relieve those constraints (clause 5.6.5).

- Annual Planning Reports (APRs) (published by TNSPs)—details on emerging congestion over the next 10-15 years and options for addressing it (clause 5.6.2A).

C.6.2 Discussion

Our proposal, in the Directions Paper, to improve the provision of information to market participants, received the support of all submissions. There were, however, some qualifications. The transmission owners, ETNOF, suggested that when considering what information TNSPs might provide, we should take into account that: (a) the provision of information is not without cost; (b) information must be meaningful and practical to provide; and (c) information should only be required through the Rules if normal market activities will not delivery it and/or cannot be provided on an user-pays basis. The Southern Generators pointed out that more information would have limited effectiveness because it would not in itself address the problems arising from congestion.

As the Review progressed, we identified two specific areas of information where change is warranted:

- real-time information on planned network events affecting dispatch; and

- information on the incidence and patterns of mis-pricing.

Each of these is discussed in turn.

C.6.3 Real-time information on planned network events affecting dispatch

Market participants need to take measures to manage the impact of constraints, and when they cannot accurately predict the timing of constraints, they find themselves exposed to both physical and financial risk.

Currently, NEMMCO and TNSPs advise participants about network outages through several publications. These are the PNO information, the NOS, and Market Notices. The NOS is currently published by NEMMCO voluntarily. The NOS and PNO information provide market participants with information that is very important to their commercial and operational decisions.

Given the importance of outage information on market outcomes, we believe the Rules should require NEMMCO to publish the information in the NOS and continue to require NEMMCO to publish the PNO information. This information will enable participants to understand, predict, and appropriately respond to those events.

The NOS and the PNO information report on network outages only. There are other types of "events" that affect network constraints. Other factors affecting which constraints NEMMCO invokes include the completion of a network augmentation, the commissioning of a new generator, the decommissioning of an old plant, or the connection of a new industrial load. These factors change the way electricity flows across the network and therefore require new constraint equations to represent the new network configuration. Events such as these can affect which constraint equations are used by NEMMCO, and therefore a market participants ability to understand and manage those trading risks associated with network congestion

For market participants however, there is an information gap for some of these events which affect constraints. For example a TNSP may decide to augment a particular part of the network and will notify the market of this through its APR. For some augmentations, the next time the market hears about the progress of this network change is through a Market Notice from NEMMCO notifying participants about a new constraint equation reflecting this network investment. This gap in information can span several months. Throughout this period, participants face uncertainty over the process between the decision to invest in the network and the inclusion of the new constraint equation reflecting the augmented network into the constraint library, where NEMMCO can use it in market dispatch.

We believe that greater clarity and predictability regarding the impact of a TNSP's actions on likely transfer capability, and on the ultimate expression of this in constraint equations, will be of considerable benefit to participants. We therefore recommended in the Draft Report that NEMMCO should be required to publish information about events (including but not limited to network outages) that may result in different constraint equations being formulated and/or invoked. These events include: network outages; the connection and disconnection of generating units or load; the commissioning (and decommissioning) of new network assets and new or modified NCAS; and network support agreements. Collectively, these events will be defined in the Rules as "planned network events". Information on planned network events will help provide a richer and more continuous flow of information to participants about how these events may affect network capability.

We also recommended that NEMMCO publish information to improve the ability of participants to track and predict changes to the timing of outages and to understand the reasons for changes to outage start and end dates. The NOS does not currently provide all this information. Such information may also place greater discipline on TNSPs and/or NEMMCO to schedule accurately outages, as far as practicable.

NEMMCO currently does not issue market notices to inform market participants when constraints affecting network transfers purely within a region are changed (i.e. when a distribution asset is returned to service following an outage). Market participants have indicated that in order to ascertain when they will be affected by such transfer limits, they rely on informal relationships with network business. The above recommended information outages will help address this problem.

The majority of submissions to the Draft Report supported the recommendation that NEMMCO publish information about congestion-related network events.[295] For example, EUAA noted that this should: (a) enable generators to better anticipate the impacts of constraints; (b) enable retailers to better manage price risk; and (c) reduce information asymmetry.[296]

There were some reservations and qualifications, however.

NEMMCO sought further clarification on the objective of the information resource. In particular, it wanted clearer guidance on what information would assist participants in understanding and predicting the nature and timing of events likely materially affect constraints. It also pointed to the MMS as a useful resource for constraint information and suggested ways to improve it as resource for participants.[297]

Hydro Tasmania supported better information provision to the market so long as the costs of providing it did not exceed benefit to the market. It recommended the establishment of a consultative working group to clarify what information is available and to determine the most constructive and accessible presentation forms and quality control processes.[298]

The NGF proposed that the development of an information resource should be pursued incrementally so as avoid creating an unnecessary reporting burden upon NEMMCO.[299]

ETNOF was concerned that TNSPs may be held legally liable for the decisions of participants who rely on the information.[300] ETNOF suggested the Rules should limit TNSP and NEMMCO liabilities to third parties. This would reduce customer

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295 NGF, Draft Report submission, p.9; CS Energy, Draft Report submission, p.3; EUAA, Draft Report submission, p.29; Origin, Draft Report submission, p.1.

296 EUAA, Draft Report submission, pp. 27-8

297 NEMMCO, Draft Report submission, pp. 7-8

298 Hydro Tasmania, Draft Report submission, p.3

299 NGF, Draft Report submission, p.9

300 ETNOF, Draft Report submission, p. 2

costs and act a an incentive for TNSPs to provide information more freely. ETNOF also noted that significant effort is required by TNSPs to fulfil an obligation to publish data for a large number of flow paths.[301]

In our final recommendation, we recommend that NEMMCO must develop and publish information that enables market participants understand patterns of network congestion. This includes information to help predict the nature and timing of events that are likely to affect materially what constraints NEMMCO uses in dispatch. This information will be included in a dedicated CIR, which will also include information on mis-pricing (discussed next). In finalising this recommendation, we considered the issues and suggestions raised in submissions. These comments informed how we propose to implement this recommendation, discussed in section C.6.4.

C.6.3.1 Information on the incidence and patterns of mis-pricing

In the Directions Paper, we suggested that NEMMCO could publish information on the mis-pricing[302] of generation to enable participants to better manage congestion in the medium to long term. We suggested that this information could:

- be in the form of published nodal prices *or* differences between the RRP and nodal prices;
- identify whether the constraint that caused the mis-pricing was an outage constraint or a system normal constraint; and
- identify the network element or cut-set on which the limitation arose.[303]

Responses from submissions were varied.

The Southern Generators supported the publication of nodal prices. However, they expressed concern that potential entrants may be unfamiliar with the idiosyncrasies of NEM pricing and may not appreciate that generators are not actually settled at their nodal price; therefore the publication of mis-pricing data ought to be accompanied by explanation to ensure it is not misinterpreted.

Powerlink expressed concern that any obligation to provide information should not expose the TNSPs to the risk of being held responsible for the wisdom of investment decisions made by new investors.

Regarding the publication of nodal prices, NEMMCO thought this would require a substantial ongoing commitment of resources.[304] It suggested that information on

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301 ETNOF, Draft Report submission, p. 5

302 The concept of mis-pricing is described in chapter 2 of this Review's Final Report and Appendix A

303 AEMC, Congestion Management Review, Directions Paper, 12 March 2007, p.60.

304 Nodal prices are calculated as the marginal cost of supply at each node (refer to Appendix A for a more detailed explanation of nodal pricing). To determine accurately all nodal prices in the NEM, NEMMCO would probably need to run a full-network dispatch and pricing model in parallel to the current dispatch model.

mis-pricing based on constraint shadow prices would be simpler to produce and just as useful to market participants. NEMMCO also noted that it already publishes substantial information on constraints and that there would be merit in exploring how the provision of further data on mis-pricing could be expected to improve participants' responses to congestion.

The routine publication of mis-pricing information will be valuable in identifying specific points of congestion, where targeted measures, like network support agreements, could be implemented to assist in the management of congestion. Mis-pricing information will assist participants in identifying areas where they themselves can negotiate such agreements.

Investors will also find value in mis-pricing information as a tool in their decision-making processes. While investment locational decisions are based on a range of factors including access to fuel and water and environmental considerations, access to transmission is also important. Information on mis-pricing will help inform investment location decisions, identifying possible congested areas and therefore prompting a comprehensive assessment of congestion at a preferred location.

In the Draft Report we recommended that NEMMCO develop a methodology in consultation with participants for the production of mis-pricing information that covers all material congestion in the NEM. We recommended that this information be published on a quarterly basis, and that NEMMCO's other resource commitments be taken into account when establishing the commencement date.

All submissions to the Draft Report[305] supported the recommendation, saying that it would improve transparency in the production of mis-pricing information[306] and would be more indicative of the materiality of mis-pricing.[307] Hydro Tasmania suggested using working groups in the consultation phase.[308]

As to the commencement date for the development of a methodology and publication of mis-pricing information, EUAA did not support the proposal that NEMMCO be able to vary the date based on its resource commitments.[309] Instead, its view was that NEMMCO must produce this information in accordance with the Rules. EUAA was the only submission on this particular point.

We are subsequently recommending that NEMMCO publish information on the extent and pattern of mis-pricing as part of a single, comprehensive Congestion Information Resource. After consideration of submissions, the specifics of how NEMMCO should publish mis-pricing information and when it should start will be subject to stakeholder consultation. We set out the details of how to implement this recommendation in the following section.

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305 Origin Energy, CS Energy, InterGen, NGF, Hydro Tasmania Draft Report submissions.

306 CS Energy, Draft Report submission, p.3.

307 EUAA, Draft Report submission, p.29.

308 Hydro Tasmania, Draft Report submission, p.3.

309 EUAA, Draft Report submission, p.29.

C.6.4 Final recommendations and implementation

We recommend that NEMMCO be required to publish a single, central resource for congestion-related information—the CIR. The objective of the CIR:

> "is to provide information in a cost effective manner to Market Participants to enable them to understand patterns of network congestion and make projections of market outcomes in the presence of network congestion."

This will provide information on planned network events, informing market participants about which constraint equations NEMMCO will use in dispatch. The CIR will also include historical information on the occurrence and materiality of all mis-pricing in the NEM caused by congestion.

Better information about which constraint equations will be included in dispatch will improve participant decision making. The CIR will provide the most up to date information on network outages and other planned network events. This will provide participants with a better understanding of how potential changes in system conditions are likely to affect network constraints and therefore influence dispatch. Improvements in information will translate into more informed an deficient decision making for participants.

The more frequent and regular publication of information on the prevailing patterns of congestion under different network conditions, e.g. in the presence of outages, and under system normal conditions, will also help policy makers and market participants understand patterns and trends in the incidence of congestion. This can inform participants' contracting and investment decisions and thereby assist congestion management in the longer term. Furthermore:

- Planned network events must include, at a minimum: network outages; connection and disconnection of generating units or load; commissioning (or decommissioning) of network assets or new or modified NCAS; and NSAs.
- NEMMCO must publish this resource on a timely basis and must publish updates as soon as practicable.
- In developing or modifying this CIR, NEMMCO must consult with stakeholders.
- The CIR is a continually evolving source of information for the market.
- TNSPs and other Registered Participants are obliged to provide information requested by NEMMCO to develop this resource.

Implementation

The *Draft National Electricity Amendment (Congestion Information Resource) Rule 2008* (CIR Draft Rule) can be found in Appendix G.

We have adopted an objectives-based approach to the implementation of the CIR. By this we mean that in the CIR Draft Rule we have:

- removed the current high level of prescription in the Rules dictating exactly what information NEMMCO and TNSPs must provide; and
- replaced this with a high-level objective (clause 3.7A(a), specify guidelines (clause 3.7A(k)), and the outline of a process by which the CIR can be amended subject to stakeholder consultation (clauses 3.7A(l) and (m)).

This will allow NEMMCO, TNSPs, other information providers, and those who use the information, to determine the most beneficial sources of information, the most appropriate form of publication, and an efficient publication timetable.

The CIR Draft Rule stipulates that the CIR must be a source of information on: (1) planned network events that are likely to materially affect network constraints; and (2) historical data on mis-pricing in the NEM.

Following submissions on the Exposure Draft of this Rule[310], the definition of "mis-pricing" has been amended. Mis-pricing is now defined as the difference between the RRP and an estimate of the marginal value of supply.

We do not expect this objective to be attained in the first CIR to be published. Instead, as a transitional arrangement, we require of this initial CIR only that it formalise the provision of information on planned network events currently published by NEMMCO and TNSPs (rule 11.X).[311]

NEMMCO expressed concern that aspects of the interim CIR (published under 11.X) were unclear.[312] These have now been addressed. In particular, clause 3.7A(c) now states that the CIR must contain the same level of detail as the interim CIR. Clause 3.7A(d)(3) now requires NEMMCO to amend the CIR where such an amendment furthers the CIR objective. Finally, under clause 11.X.2(a), the development of the interim CIR is exempt from following the Rules consutation proceedure.

Grid Australia commented that the draft Rule might be construed to mean that TNSPs are required to undertake works planning two years in advance. This is not necessary and clauses 11.X.1 and 11.X.2(h)-(j) make this clear.

ETNOF expressed a concern that network businesses may be liable for the information they provide to the market. The CIR Draft Rule takes this into account: proposed clause 3.7A(p) states explicitly that any information provided to the market is the "best estimate" of the information provider. However, the proposed Rule also places the onus on the information provider to ensure that they provide the most up-to-date information to the market in a timely fashion ("as soon as practicable") (clauses 3.7A(n) to (p)).

Clause 3.13.4(y) includes a requirement that NEMMCO publish the CIR in accordance with "the timetable" in the Rules.

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310 AEMC 2008, Congestion Management Review, Exposure Draft, March 2008, Sydney. Available: www.aemc.gov.au.

311 See section C.6.1 for a list of the existing sources of information.

312 NEMMCO, submission on Exposure Draft, 15 April 2008.

It is for NEMMCO to determine whether or not the most productive process for undertaking consultation includes convening an industry working group.

C.7 Terms of Reference

While most of the submissions to the Draft Report implicitly accepted our interpretation of the Ministerial Council of Energy's Terms of Reference, the ERAA thought that we took a narrow view. It proposed that a wider and more comprehensive examination of transmission pricing and development rules should have been undertaken.[313]

EUAA also had concerns about our interpretation of the Terms of Reference. It stated that we introduced a concept of "feasibility" in interpreting the Terms of Reference. It did not consider that the Draft Report sufficiently analysed the impacts of congestion on either end users or retailers in terms of final delivered prices.[314]

Discussion

In undertaking this Review, we undertook three rounds of general consultation and a number of supplementary consultations on specific issues. We considered a range of related reviews and Rule changes that addressed congestion related issues to ensure a co-ordinated comprehensive assessment of the issues we and stakeholders identified. We also considered all our recommendations against the National Electricity Objective, which is directed at promoting efficient outcomes for consumers of electricity.

[313] ERAA, Draft Report submission, p.1

[314] EUAA, Draft Report submission, p.11

C.8 Evidence base / Approach to analysis

There was considerable debate in submissions to the Draft Report about our conclusions on the materiality of congestion

Some submissions supported our conclusions, agreeing that having resolved the congestion problem in the Snowy region, the outstanding level of congestion in the NEM was relatively immaterial.[315] These submissions therefore supported the recommendations put forward in the Draft Report, agreeing they were proportionate and incremental relative to the degree and materiality of congestion.

Several submissions were critical of the materiality findings. The main issue was our considerations of dynamic efficiency. Many submissions considered that this measure of longer term materiality was insufficiently address, which in their view, let to an erroneous conclusion that congestion was not a material problem. Another concern was that our historical analysis of productive efficiency measures did not effectively project future changes in congestion.

The ERAA, "the Group", Hydro Tasmania, Babcock and Brown Power, the Government of South Australia and the EUAA all considered additional analysis on dynamic efficiency effects was necessary in order to determine whether or not congestion was a material problem. While many of them noted the difficulties in measuring dynamic efficiency gains, they considered congestion was growing and this was not evident in the historical analysis presented.[316]

"The Group" focused on our interpretation of the IES report, which attempted to measure the dynamic efficiency benefits of increasing the degree of locational pricing in Queensland.[317] It argued that, notwithstanding our concerns about the report produced, it should not have been dismissed as it showed that there were demonstrable dynamic efficiency gains to be made.

VENCorp was concerned that analysis of the data skewed results to show that congestion was immaterial. It stated that the appropriate way to measure the materiality of congestion was to compare congestion costs against estimated costs of implementing measures to remove or relieve congestion.[318]

Some submissions said that failing to improve generator access rights to the transmission network would lead to material congestion.[319]

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[315] Snowy Hydro, Draft Report submission, p.1; ETNOF, Draft Report submission, p.1; Macquarie Generation, Draft Report submission, p.1.

[316] ERAA, Draft Report submission, p.3; "the Group" Draft Report submission, p.2; Hydro Tasmania, Draft Report submission, p.2; Babcock and Brown Power, Draft Report submission, p.5; Government of South Australia, Draft Report submission, p.1; EUAA, Draft Report submission, p.12.

[317] Loy Yang Marketing Management Company, AGL Energy, International Power, Flinders Power, InterGen Australia and Hydro Tasmania, Draft Report, submission, pp.2-3.

[318] VENCorp submission, p.1.

[319] NGF, Draft Report submission, p.2; InterGen, Draft Report submission, p.1; The Group, Draft Report submission, pp.15-17.

Other submissions posed that even if congestion did not appear to be a material problem today, it had the potential to increase dramatically with time. Therefore, the market required a location-specific interim constraint pricing mechanism to be able to manage congestion if and when it arose.[320]

Discussion

For this Review, we undertook an evidence-based approach to evaluating the materiality of congestion. In the Draft Report, we highlighted the need to consider the impacts of congestion on productive (dispatch) efficiency, risk management and forward contracting, and dynamic efficiency.

Our recommendations have been informed by relevent evidence on the prevalence and materiality of congestion in the NEM. Much of this evidence is based on experience in the recent past. While this type of evidence can provide valuable insights, it also has limitations. We need to be aware of the possibility that patterns of congestion might materially change in the future, and seek to identify and understand the drivers for any such changes.

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

We need to recognise and seek to understand both the short-term and the long-term implications of congestion, especially in light of the significant amount of planned energy investment over the next five to fifteen years. We considered several approaches and data sources. We have also considered future market developments and the potential impact on the materiality of congestion, and what the pressures might be on the current Rules and regulatory framework in this context including informed by submissions from market participants.

The CM Regime we recommend in this Final Report, including our recommended changes, represents an efficient and proportionate framework for managing congestion. However, we are aware that there are a range of factors shaping the future development of the NEM that, collectively, will put new and different pressures on the CM Regime. The two most obvious factors are:

- the general tightening of balance between supply and demand, with continuing strong growth in the demand for electricity and a smaller rate of growth in the supply of new generation capacity; and

[320] Origin Energy, Draft Report submission, p.1; ESAA, Draft Report submission, p.1; ERAA, Draft Report submission, p.3.

- policy responses to climate change, such as an ETS and MRET scheme, which will change significantly the underlying economics of the market and will influence short-term and long-term behaviour in the market.

We have a statutory role in respect of market development. It is therefore important and appropriate for us to consider, more broadly and on an ongoing basis, whether the current market design and Rules are likely to continue to promote efficient outcomes for consumers in the light of these new developments. This consideration includes, but is wider than, the details of the CM Regime. There are many interactions between changes to the CM Regime and changes to others aspects of the regulatory framework, and partial assessment runs the risk of unintended consequences and less efficient outcomes.

We therefore considered these issues in more detail and highlighted interactions between other related policy initiatives, such as the establishment of a NTP and reform of the current regulatory test for transmission investment decisions in chapter 4 of this Final Report. We also documented some of the options that might have relevance to this debate, including options for change which have been raised by stakeholders through the course of the Review but which, in our view, fell outside the scope of this Review.