Australian Energy Market Commission

REVIEW

DIRECTIONS PAPER

Transmission Frameworks Review

Commissioners

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14 April 2011

Reference: EPR0019
Directions Paper

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Reference: EPR0019

Citation

AEMC 2011, *Transmission Frameworks Review*, Directions Paper, 14 April 2011, Sydney.

About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. The AEMC has two principal functions. We make and amend the national electricity and gas rules, and we conduct independent reviews of the energy markets for the MCE.

Executive summary

The Australian Energy Market Commission's Transmission Frameworks Review provides an important opportunity to ensure that the regulatory arrangements governing transmission networks in the National Electricity Market (NEM) are robust and will be effective in facilitating efficient market outcomes.

This is critical given the significant changes being experienced in the NEM. Substantial investment in all stages of the electricity supply chain is required to maintain reliable electricity supply, and policies aimed at addressing climate change concerns will drive major new investment in renewable and low carbon generation. This is likely to have significant effects on the level and pattern of transmission investment in the long term, as well as leading to changes in network flows in operational timescales.

Transmission frameworks therefore need to ensure that investment and operational decisions across generation and transmission are optimised in a manner that minimises the overall costs imposed on consumers, while facilitating the continued security and reliability of supply.

Stakeholder engagement

As a first step in this key review, the Commission published an Issues Paper, which prompted a significant reaction from industry stakeholders. Twenty-eight submissions were received, and the breadth and depth of issues discussed in these revealed a diverse range of views on the robustness of the existing transmission frameworks and their interaction with the generation sector.

The Commission has since received a further three supplementary papers, as stakeholders continue to debate issues raised in submissions to the Issues Paper. The review has also already led to the establishment of a number of industry working groups seeking to resolve some of the problems identified to date.

This paper

This Directions Paper sets out the Commission's initial response to the issues raised in submissions. It also seeks to sharpen the focus of the review by identifying key themes for further analysis and development during the next stage of the consultation process.

In doing so, the paper reports back on stakeholder feedback and sets out a characterisation of issues around:

- **The nature of access.** The issue of generator access has been debated since the inception of the NEM. The next step in this review will be to further inform and develop this debate by undertaking a thorough examination of the rationale, and potential options, for providing generators with a defined level of transmission service.

- **Network charging.** The nature of the service provided by transmission, including access, is closely linked with the issue of how charges to generators and users should be structured. Following further consideration of the nature of access, the review will consider the costs imposed by generators and users under different transmission service models and the consequent design issues for charging.

- **Congestion.** Congestion on the network has wide-ranging consequences for the efficient operation of the market, and will effect the level of access delivered to generators. However, there has been little agreement to date on the materiality of congestion, and potential solutions proposed have been highly complex. An important aspect of this review going forward will therefore be to assess this trade-off between the materiality of network congestion and the complexity of options to address its impacts.

- **Planning.** The way in which the network is planned is strongly tied to the service provided by transmission, and may provide an alternative means to resolving some of the issues around congestion. The next stage of this review will therefore consider issues related to the provision of services by transmission through network investment and non-network solutions. This will include examination of the practical application of the regulatory test used for assessing transmission investments and consideration of the relevant institutional arrangements.

- **Connections.** A significant number of stakeholders have raised a series of concerns regarding the effective operation of the existing connections framework. In response to this stakeholder feedback, the review will now include consideration of issues such as the negotiating frameworks, interactions between connections and the shared network, and jurisdictional variations.

Next steps

Following further in-depth analysis of each of the above issues, the Commission will publish a First Interim Report. It is intended that this will set out a number of comprehensive and internally consistent 'policy packages'. These packages will synthesise the findings from across the five key themes to provide a spectrum of potential options for stakeholder consideration and assessment.

The Commission will continue to engage with stakeholders as the review progresses, including through the review’s stakeholder Consultative Committee. Although this paper does not pose any specific questions, the Commission is seeking comment from stakeholders on the way it has framed the issues and whether this represents an appropriate structure for the review going forward.

Contents

1 Introduction and background

1.1 Introduction

The Transmission Frameworks Review is a key project for the Australian Energy Market Commission (AEMC or Commission) in progressing its strategic priority of ensuring the delivery of efficient and timely investment in transmission. The transmission networks and their future augmentation will be critical to ensuring continued security of supply and the meeting of environmental targets.

A framework that promotes the efficient provision of transmission services to competitive and other regulated sectors of the National Electricity Market (NEM) will have a number of key characteristics. These include:

- Ensuring that the capacity in the existing transmission network is used as efficiently as possible with the costs faced by those parties that value using the network the most.
- Minimising the costs associated with managing the operation the current network to meet system security, reliability and safety requirements.
- Timely investments in new infrastructure at locations that reflect expected future demand and generation capacity, by considering whether the benefits of investing outweigh the costs.

The operation of transmission networks and investment in new infrastructure requires an interaction between companies operating in a competitive market and regulated network service providers. Therefore, a robust framework requires that regulated networks have the right incentives to consider and meet the needs of users and generators in competitive markets. Equally, these users and generators should face appropriate incentives to ensure that overall costs are minimised. The facilitation of demand-side response and use of non-network solutions will also be important in ensuring overall efficiency.

These factors are of particular importance given the significant period of change being experienced in the NEM. Substantial investment in all stages of the electricity supply chain is required over the next decade in order to maintain secure and reliable electricity supplies. Policies aimed at addressing climate change concerns are expected to drive major new investment in renewable and low carbon generation. This is likely to have significant effects on the level and pattern of transmission investment in the long term, as well as leading to changes in network flows in operational timescales.

1.2 MCE direction

In response to these challenges, on 20 April 2010, the Ministerial Council on Energy (MCE) directed the Commission to conduct a review of the arrangements for the provision and utilisation of electricity transmission services and the implications for the market frameworks governing transmission investment in the NEM.

The Terms of Reference specifies that the AEMC's review should focus on identifying any inefficiencies or weaknesses in the inter-relationship between transmission and generation investment and operational decisions under the current market frameworks and amendments recently approved, particularly in light of the anticipated impacts of climate change policies and the potential impacts of extreme weather events.

The MCE noted that:[1]

> "Where appropriate, the AEMC should recommend changes which would better align incentives for efficient generation and network investment and operation with a view to promoting more efficient and reliable service delivery across the integrated electricity supply chain."

In conducting the review, the AEMC is to consider the following key areas together in a holistic manner:

- transmission investment;
- network charging, access and connection;
- network operation; and
- management of network congestion.

This requirement to undertake a comprehensive review reflects the integrated nature of transmission frameworks, which is particularly important given the inter-related nature of the issues involved and of changes that may be developed.

The full MCE direction is available on our website at www.aemc.gov.au.

1.3 National Electricity Objective and the MCE direction

The AEMC is required to have regard to the National Electricity Objective (NEO) in every review it undertakes and every change to the National Electricity Rules (NER or Rules) that it assesses. The NEO will therefore form the overarching principle for the assessment framework used to evaluate potential transmission reforms.

The NEO is set out in section 7 of the National Electricity Law (NEL), which states:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to-

1 MCE, *Terms of Reference - AEMC Transmission Frameworks Review*, April 2010, p. 3.

(a) price, quality, safety, reliability and security of supply of electricity; and

(b) the reliability, safety and security of the national electricity system."

The AEMC has been directed to undertake this review by the MCE under the powers established by section 41 of the NEL. This provides, amongst other things, for the AEMC to conduct a review into any matter relating to the NEM.

In reviewing the existing arrangements for transmission in the NEM and identifying any options for reform, the MCE direction specifies that the AEMC should have regard to the NEO and to certain principles previously agreed by the Council of Australian Governments (COAG) in relation to earlier reforms. As outlined in the MCE direction, these principles are that:[2]

- "accountability for jurisdictional investment, operation and performance will remain with transmission network service providers;
- where possible, the new regime must at a minimum be no slower than the present time taken to gain regulatory approval for transmission investment; and
- the new regime must not reduce or adversely impact on the ability for urgent and unforeseen transmission investment to take place."

When considering potential proposals to amend the market frameworks, the AEMC is also to have regard to the implications for trading and contracting risks and for investment and regulatory uncertainty, as well as the need for transitional and other arrangements to mitigate or manage such risks.

1.4 Policy context: recent related initiatives

This review builds on a number of related initiatives that have been undertaken in relation to arrangements for transmission. The most relevant of these are highlighted below.

1.4.1 Congestion Management Review

On 5 October 2005, the MCE directed the AEMC to review congestion management in the NEM. We were asked to examine and report on improved arrangements for managing financial and physical trading risks associated with material transmission congestion, and the feasibility of developing a congestion management regime for managing material congestion at a particular location until it is addressed by investment or a regional boundary change.

We provided a final report of the Congestion Management Review (CMR) to the MCE on 16 June 2008, in which we recommended a number of Rule changes focussed on

2 Ibid, p. 2.

enhancing the quality of information available to market participants to help them understand the risks associated with congestion, and on improving the effectiveness of risk management instruments.[3] Importantly, we also foreshadowed that more significant reforms to frameworks might be warranted as a result of then forthcoming government policy initiatives in response to climate change concerns.

1.4.2 National Transmission Planner

On 3 July 2007, the MCE directed the AEMC to develop arrangements for the national transmission planning function, as specified in the COAG decision of 13 April 2007.

We provided a final report to the MCE on 30 June 2008, in which we made a number of recommendations relating to:

- the establishment of the National Transmission Planner (NTP) as one of the functions of the Australian Energy Market Operator (AEMO);
- the annual publication by the NTP of the National Transmission Network Development Plan (NTNDP); and
- the introduction of a new Regulatory Investment Test for Transmission (RIT-T) to replace the existing Regulatory Test.

The NTP function was assumed by AEMO at its establishment on 1 July 2009, and it published an interim NTNDP (called the National Transmission Statement) on 17 December 2009. The arrangements for the RIT-T commenced operation on 1 August 2010, and the first full NTNDP was launched on 15 December 2010.

1.4.3 Transmission Reliability Standards Review

Also on 3 July 2007, and further to the COAG decision, the MCE directed the AEMC to conduct a review into electricity transmission network reliability standards, with a view to developing a consistent national framework.

We provided a final report to the MCE on 30 September 2008, in which we made recommendations for a national framework to promote consistency in transmission reliability standards, and for the implementation of this framework. On 10 December 2010, we published an Updated Final Report for this review. This updates and clarifies a number of detailed recommendations previously made, but does not substantively change our proposal that a national framework for transmission reliability standards should be introduced.

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3 For a full list of the recommended Rule changes, please see: AEMC 2008, *Final Report*, Congestion Management Review, June 2008, Sydney. Note that of the four recommended Rule changes, three were subsequently made, subject to some modifications by the Commission. The Commission was of the view that the fourth, the proposed National Electricity Amendment (Network Augmentations) Rule 2009 should not proceed as a number of issues relevant to the proposal were being considered as part of the *Review of Energy Market Frameworks in light of Climate Change Policies*.

1.4.4 Review of Energy Market Frameworks in light of Climate Change Policies

In August 2008, the AEMC commenced a review of Australian energy market frameworks to determine whether they required amendment to accommodate the introduction of a Carbon Pollution Reduction Scheme (CPRS) and the expanded Renewable Energy Target (RET).

In our final report, provided to the MCE on 30 September 2009, we concluded that energy market frameworks were generally capable of accommodating the impacts of climate change policies efficiently and reliably. However, we found that changes to network flows arising from changing patterns of generation would create pressures for network investment in the long term and would be likely to increase the prevalence of network congestion arising in the short term. We therefore recommended a number of specific changes in respect of the shared transmission network in the NEM. These were that:

- a transmission change should be introduced to signal network costs to generators, in particular the extent to which costs vary by location;
- where practical and proportionate, the prices generators receive in the wholesale market should reflect network congestion, in particular where there are pockets of material and transitory congestion; and
- in principle, generators should be able to pay for and receive an enhanced level of transmission service to manage risks around constraints and dispatch uncertainty.

We noted that the detailed implementation of these recommendations would require development by the AEMC in consultation with stakeholders. The requirement to undertake this further work led to the initiation of this Transmission Frameworks Review.

In our final report, we also recommended two other framework changes of potential relevance to this review. These recommendations were subsequently endorsed by the MCE, which submitted two Rule change requests:

- the **Scale Efficient Network Extension** (SENE) Rule change request, which sought to provide a framework for the more efficient connection of multiple generators in the same geographic areas that seek connection to the network over time; and
- the **inter-regional transmission charging** Rule change request, which sought to improve the cost-reflectivity of transmission charges and the allocation of costs across regions.

We note that a draft Rule determination was published for the SENE Rule change request on 10 March 2011.[4] The Commission's draft decision was to implement a more

4 AEMC 2011, *Scale Efficient Network Extensions*, Draft Rule Determination, 10 March 2011, Sydney.

preferable Rule that creates a new obligation on transmission businesses to undertake, on request, a locational study to reveal to the market the potential opportunities for efficiency gains from the coordinated connection of expected new generators in a particular area. The Commission also noted that broader issues around access rights and connection that were raised in consideration of the Rule change would be considered as part of this review.

On 7 April 2011, the Commission gave notice under section 107 of the NEL to extend the period of time for the making of the final Rule determination for the inter-regional transmission charging Rule change to 23 February 2012. The Commission decided that such an extension was warranted to develop a consistent national design for the inter-regional transmission charging mechanism and the methodology for calculating that mechanism. This matter is discussed further in chapter 5.

1.4.5 Review of Demand-Side Participation in the NEM

The MCE has agreed a Terms of Reference for a third stage of the AEMC's Review of Demand-Side Participation (DSP) in the NEM (Stage 3 DSP Review). More information about the MCE Terms of Reference for the Stage 3 DSP Review can be found on our website at www.aemc.gov.au.

On 20 July 2010, the MCE released its response to the AEMC's Stage 2 Final Report on DSP in the NEM. The MCE, as part of that response, supported the need for a further stage of the review to consider the implications of developments in smart grid and smart meter technologies in the NEM. The MCE has also indicated that the Stage 3 DSP Review should have a broader focus, and consider a number of other issues specifically related to the efficient operation of price signals and effectiveness of regulatory arrangements for energy efficiency.

We further note the MCE's support for the equal consideration of supply-side and demand-side options and implications as part of all future AEMC reviews. In the Transmission Frameworks Review, we intend to consider the arrangements applying to both generation and load, and this will therefore fully include the demand-side as well as the supply-side.

1.5 Responding this paper

Although this Directions Paper does not pose any specific questions, the Commission is seeking comment from stakeholders on the way it has framed the issues, and whether this represents an appropriate structure for the review going forward.

How to make a submission

The closing date for submissions to this Directions Paper is 26 May 2011.

Submissions should quote project number "EPR0019" and may be lodged online at www.aemc.gov.au or by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

1.6 Structure of this paper

The remainder of this Directions Paper is structured as follows:

- **Chapter 2** provides a high level overview of the range of issues raised in submissions to the Issues Paper, highlighting the divergent views presented by stakeholders and sets out the timetable for the progression of the review;
- **Chapter 3** outlines the way in which the Commission intends to apply the NEO during the review and discusses the role of transmission in the NEM;
- **Chapter 4** discusses the issues relating to access rights that were raised by stakeholders and sets out specific areas for further consideration, including potential frameworks for providing generators with firmer access;
- **Chapter 5** elaborates on the network charging workstream, including a discussion of the costs imposed by generators on the network under current frameworks, the impact of changes to access arrangements, design issues for potential generator charges and charges for load;
- **Chapter 6** discusses the materiality of network congestion and options to address this, specifically with regards to promoting the efficiency of dispatch;
- **Chapter 7** discusses planning issues, particularly around transmission reliability standards for load, the test for transmission investment, inter-regional transmission investment, proactive planning and institutional arrangements; and
- **Chapter 8** discusses the issues raised by stakeholders on the current connections regime, most notably the negotiating framework, interactions with the shared network and jurisdictionally specific matters.

2 This paper and the process for the review

2.1 Purpose of this Directions Paper

This Directions Paper is intended to consider the issues raised by stakeholders and set out how the Commission intends to progress these issues in the review.

The remainder of the Directions Paper therefore:

- discusses the issues raised in submissions;
- identifies the issues that will be progressed further under the review;
- provides a framework for the further consideration of these issues; and
- sets out the process and timetable for completing the review.

This chapter provides a high level overview of submissions to the Issues Paper and the framework to be adopted for the review going forward, as well as the process and timetable for the review. Subsequent chapters then discuss the issues for further consideration in more detail.

2.2 Submissions to the Issues Paper

The Issues Paper for the review was published on 18 August 2010. In the paper, the Commission noted its intention to conduct a broad ranging review of transmission frameworks and that it would welcome the views of interested parties in relation to any of the matters discussed in the document. However, to help focus responses, we asked ten specific questions, which are described later.

In particular, we requested stakeholder views as to:

- whether we had identified the scope of the issues appropriately;
- whether there were other issues that should be considered; and
- which issues were most material.

Submissions to the Issues Paper closed on 29 September 2010. The Commission received 28 responses, from a range of market participants, consumer and large end-user groups, governments and market institutions.

Submission by stakeholder type

Stakeholder type	Submissions
Generators, retailers and associated bodies	12
Network service providers and associated bodies	6
Consumer groups and end-users	3
Governments and market institutions	4
Consultancies, other	3

A full list of the submissions can be found at www.aemc.gov.au.

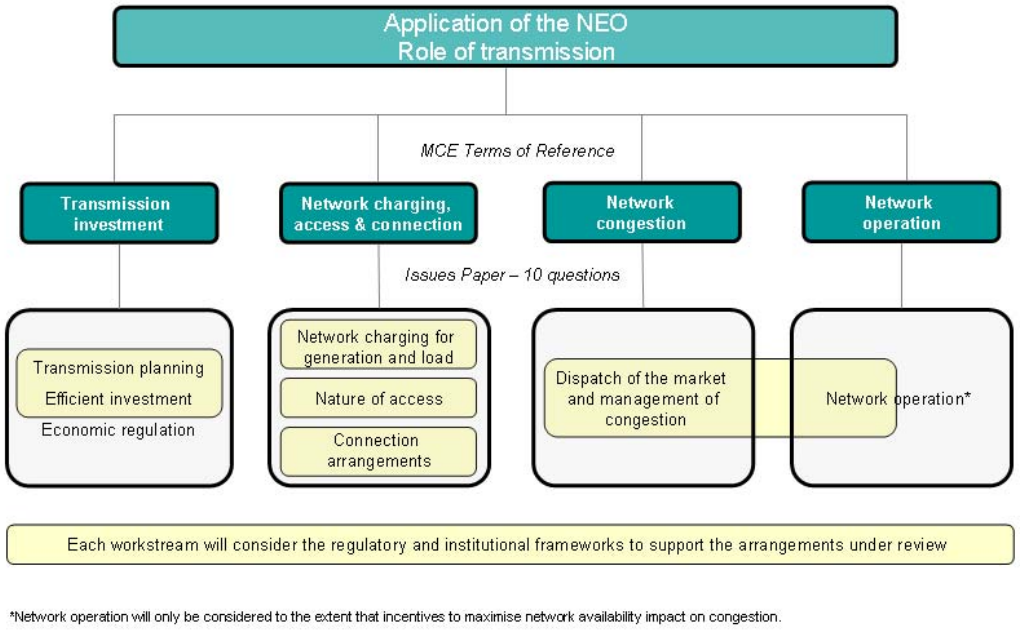
The breadth and depth of submissions received in response to the Issues Paper reveal a diverse range of views on the robustness of current transmission frameworks and their interaction with the generation sector. A small number of submissions advocated no change to current transmission frameworks or for very significant reform. However, the majority fell within a 'middle range' of support for modifying current frameworks, although there was little agreement as to exactly which areas required amendment or how.

Having given consideration to the views outlined in submissions, the Commission has developed a framework to structure and further assess of a number of issues raised by stakeholders. This is set out in the next section.

2.3 Structure

In the Issues Paper we posed ten questions. The following diagram shows how these correspond to the four key areas identified in the MCE direction.

Figure 2.1 **Mapping of workstreams, Issues Paper questions and MCE direction**



Two overarching questions were asked in the Issues Paper about the application of the NEO and the role of transmission. These questions sought to elicit comments on the broader effectiveness of the existing frameworks and the need to consider the role of transmission in delivering services to competitive sectors within the NEM.

Three questions were asked regarding transmission investment in the NEM. These related to transmission planning, investment in transmission infrastructure and the economic regulation of transmission network businesses.

Within the scope of network charging, access and connection, one question was asked on each of these issues. These questions considered whether a network charge for generation is required to provide signals for efficient investment; whether the ability for generators and load to obtain an enhanced level of transmission service would promote more efficient investment and operational outcomes; and whether the current connections framework meets the needs of generators and large end-users.

The question on network congestion sought to understand whether material congestion needed to be more efficiently managed.

Finally, a question on network operation asked whether fundamental reforms are required to provide incentives for transmission network service providers (TNSPs) to manage networks more efficiently for the benefit of the market.

Workstreams for further progression of the review

The diagram above also shows how these questions relate to five workstreams that have been identified for further consideration. These workstreams are represented by the yellow shaded areas, and the Commission has characterised these as:

- transmission planning;
- network charging;
- the nature of access;
- connection arrangements; and
- network congestion.

These five workstreams are discussed in detail in chapters 4-8 of this paper.

The Commission has decided not to progress issues related to economic regulation or network operations as discrete workstreams in the review.

Economic regulation

The Commission acknowledges the importance of economic regulation as a core part of the transmission frameworks. However, this is an exceptionally complex area in its own right, and one which has close linkages to the economic regulation of distribution networks.

The Commission has concluded that to assess all the relevant issues as part of this review would lead to the review becoming unmanageable in scale, and that it therefore does not represent the most appropriate vehicle for the consideration of these issues. The Commission also notes that the categorisation of transmission services, and the forms of economic regulation applied to them, will comprise part of the considerations of the Connections workstream.

Finally, the Commission understands that the Australian Energy Regulator (AER) is already intending to review the Rules framework under which previous revenue and pricing determinations for networks have been made.

Network operation

With respect to network operation, the Commission notes that the AER expects to commence a review of the Service Target Performance Incentive Scheme in the second quarter of 2011.[5]

The Commission has also concluded, in light of stakeholder submissions to the Issues Paper and further consideration of the Terms of Reference, that the review should focus on the incentives on network businesses to operate their networks in a manner that optimises overall network availability and market efficiency. The Commission therefore intends only to give consideration to the incentives around network operation to the extent that they affect the other workstreams under the review, most notably the impacts of network availability on congestion.

5 AER, Issues Paper submission, p. 10.

2.4 The Review timetable

Under the Terms of Reference for the review, the AEMC was due to provide recommendations to the MCE in a final report by 31 November 2011. However, because of the complexities of the issues to be considered, the significant stakeholder response to date and the variety and breadth of views expressed in submissions, the AEMC sought, and has been granted, an extension from the MCE.

An indicative timetable, including the documents to be published in relation to the review, is tabled below. The final report to the MCE is now due to be delivered by 30 June 2012.

The next key step in this review will be to develop a set of internally consistent 'policy packages' for consultation and review. These packages will be underpinned by further analysis to be undertaken on each of the five workstreams. The insights gained from this further analysis will be synthesised into a set of potential models which take account of the interaction between the currently separate workstreams. These packages will be published in a First Interim Report for consultation.

Updated Review Timetable

Document	Purpose	Date
Issues Paper	To present the key issues identified by the Commission and set out the process for the review.	Published 18 August 2010; submissions closed 29 September 2010.
Directions Paper	Directions Paper replaced the previously announced Options Paper. The purpose of the Directions Paper is to address some of the key issues raised in submissions to the Issues Paper and to identify key themes that the Commission proposes to take forward and how the Commission intends to do this.	**Submissions due 26 May 2011**.
First Interim Report	To identify and discuss a short list of potential internally-consistent policy 'packages' and explain the framework for the assessment of these.	Third quarter 2011.
Second Interim Report	To assess the packages identified in the First Interim Report, and to make a draft recommendation in this respect.	First quarter 2012.
Final Report	To set out the Commission's policy conclusions and recommendations to the MCE, and to note any high-level implementation and transitional issues for further consideration.	By 30 June 2012.

2.5 Consultative committee

2.5.1 Stakeholder Consultative Committee

In accordance with the MCE direction, the AEMC has, by invitation, established a stakeholder Consultative Committee to help inform the review, including providing advice and views on our consultation documents. The membership of the Consultative Committee is comprised of representatives of AEMO, the AER, industry participants and energy end-user groups.

The Committee membership is as follows:

Stakeholder Consultative Committee: Membership

Member Organisation	Representative
Australian Energy Market Operator	David Swift, Executive General Manager: Corporate Development
Australian Energy Regulator	Warwick Anderson, General Manager: Network Regulation North
Department of Resources, Energy and Tourism	Brendan Morling, Head of Division: Energy and Environment
Energy Retailers Association of Australia	Tim O'Grady, Head of Public Policy: Origin Energy
Clean Energy Council	Russell Marsh, Policy Director: Clean Energy Council
Australian Geothermal Energy Association	Terry Kallis, Chairman: Petratherm
Grid Australia	Peter McIntyre, Managing Director: Transgrid Rainer Korte, Executive Manager: Electranet
Energy Networks Association	Dale Weber, Director, Gas and Energy Market Development: Energy Networks Association
National Generators Forum	Erin Bledsoe, Regulatory Manager: Stanwell Corporation Jamie Lowe, Manager, Regulation and Market Development: Loy Yang Marketing Management Company Kevin Ly, Manager, Market Development and Strategy: Snowy Hydro
Energy Supply Association of Australia	Brad Page, Chief Executive Officer: Energy Supply Association of Australia
Energy Users Association of Australia	Bruce Mountain, Director: Carbon Market Economics

Member Organisation	Representative
Major Energy Users	Shane Bewry, Chair: Major Energy Users
Total Environment Centre	Tyson Vaughan, National Energy Market Advocate: Total Environment Centre

Meetings of the Consultative Committee have been held:

- on 26 July 2010 in Sydney;
- on 10 December 2010 in Melbourne; and
- on 7 March 2011 in Sydney.

Outcomes of the meetings can be found at www.aemc.gov.au.

3 The role of transmission

In the Issues Paper, we posed two overarching questions about the application of the NEO and the role of transmission. This chapter discusses the stakeholder responses to these questions, and summarises the Commission's current views.

3.1 Application of the National Electricity Objective

We are required to have regard to the NEO in every review and Rule change assessment that we undertake. The NEO aims to promote efficiency in investment in, and operation and use of, electricity services for the long term interests of consumers of electricity.

A fundamental objective of this review will therefore be to assess whether the current transmission frameworks promote efficient outcomes across the supply chain. This is a complex task as there are significant linkages between decisions governing transmission investment and operation with other aspects of the supply chain, including generation and load. The framework and incentives governing transmission investment and operation will impact on the costs of generation investment and operation. Similarly, generation investment and operational decisions will impact on the costs of investing in, and operating, the transmission system.

In an efficient market, total system costs across the whole supply chain will be minimised. This includes distribution and retail as well as transmission and generation. However, the focus of this review is on the inter-relationship between generation and transmission operational and investment decisions. Therefore, for the purpose of this review, references to minimising total system costs may be considered equivalent to minimising the combined cost of investment in, and operation of, generation and transmission.

In the Issues Paper we asked whether transmission frameworks allow for the minimisation of total system costs and for overall efficient outcomes in accordance with the NEO. We also asked what evidence, if any, there was to demonstrate that this was or was not the case.

Stakeholder views

In stakeholder submissions to the Issues Paper there was widespread support for the objective for transmission frameworks that total system costs should be minimised.[6]

However, a few stakeholders suggested alternative or supplementary objectives. Grid Australia referred to the trade-off between the value of enhancements and their cost, and proposed that a more comprehensive outcome would result where net benefit was

6 AGL, Issues Paper submission, p. 1; Alinta, Issues Paper submission, p. 4; DPI, Issues Paper submission, p. 4; Northern Group, Issues Paper submission, p. 11.

maximised over the long term.[7] International Power considered an objective of minimising total costs reflects a central planning perspective, and that a major objective of transmission should be to facilitate and support competition in generation.[8] Gallaugher & Associates (Gallaugher) suggested that absolute minimisation of total system costs or maximisation of economic efficiency is unattainable because of the problems associated with planning for uncertainty.[9]

A number of stakeholders also proposed principles that could be incorporated into the market design or used as subsidiary objectives in assessing the efficiency of transmission frameworks. The suggested principles covered a broad range of framework elements, although many identified by AEMO and the Department of Primary Industries of Victoria (DPI) centred on increasing transparency (including the provision of clear cost signals) and providing a national focus for transmission.[10] The principles put forward by the Energy Users Association of Australia (EUAA) sought to reduce the scope of monopolies and of regulation to the extent possible, and to ensure that risks are borne by those best able to manage them.[11] Those suggested by the National Generators Forum (NGF) generally focussed on providing clarity of roles and services, and certainty for investors.[12]

Few stakeholders appeared to unreservedly consider that current frameworks facilitated the minimisation of total system costs. However, some stakeholders appeared to broadly support the operation of existing arrangements. EnergyAustralia noted that it was not aware of any evidence that existing frameworks do not promote efficient outcomes consistent with the NEO.[13] The Northern Group[14] considered that "there is little or no evidence to suggest that the existing framework is encouraging systematically poor operational or investment outcomes", while conceding:[15]

> “that the existing NEM transmission framework is not perfect, certainly not as measured against a highly idealised paradigm in which generation and transmission investment are co-optimised. Arguably, such an outcome can only be achieved in a centrally planned and operated electricity system. However, such centrally planned arrangements have been shown to encourage a range of other inefficiencies...”

A number of other stakeholders noted specific reasons why they considered that existing frameworks do not promote achievement of the NEO. For example:

7 Grid Australia, Issues Paper submission, p. 15.

8 International Power, Issues Paper submission, p. 6.

9 Gallaugher, Issues Paper submission, p. 2.

10 AEMO, Issues Paper submission, p. 26; DPI, Issues Paper submission, p. 4.

11 EUAA, Issues Paper submission, p. 3.

12 NGF, Issues Paper submission, p. 5.

13 Energy Australia, Issues Paper submission, p. 4.

14 This is a group of generators comprised, for the purposes of this review, of Delta Electricity, Eraring Energy, Macquarie Generation, Snowy Hydro Generation, Stanwell Corporation, CS Energy and Tarong Energy.

15 Northern Group, Issues Paper submission, pp. 11-12.

- Alinta Energy (Alinta) expressed doubts as to whether having six Transmission Network Service Providers (TNSPs) in the NEM was likely to maximise economic efficiency compared to having a single TNSP.[16]

- Infigen Energy (Infigen) noted that its experience of the current generation connection process caused it to consider that existing transmission frameworks do not allow for the minimisation of total system costs.[17]

Other stakeholders had broader concerns with the existing frameworks. For example, the Loy Yang Marketing Management Company (LYMMCo) contended that the transmission frameworks do not allow for overall efficient outcomes, including the least cost total delivered energy, and that this was evidenced by:[18]

> "a regulatory driven investment process which does not maximise competition and trade, or meets the needs of new entrant generation, allows for inefficient new entrant locational decisions to undermine incumbent generator business models, distorts hedging positions, creates TNSP investment decision dependencies which are not predictable, promotes inefficient bidding, and creates an uncertain investment environment."

The Major Energy Users (MEU) considered that the NEO is not being applied correctly and that the current frameworks allow many inefficient outcomes. It was suggested that these include the over-incentivisation of network investment, the exercise of market power by generators, the fact that price separation between regions is not used as a basis for investing in inter-regional transmission capacity, and the payment by consumers for network augmentations to accommodate environmental objectives.[19]

The Total Environment Centre (TEC) suggested that the current frameworks prevent the minimisation of total system costs and achievement of overall economic efficiency in accordance with the NEO because they do not adequately factor in demand-side response options in network planning.[20] It recommended that, in order to achieve the NEO, the review should target transmission networks as significant facilitators of demand-side participation such that this was given equal consideration in transmission network planning and investment decisions.[21]

Finally, some stakeholders contended that revisions to the NEO itself were required. The Clean Energy Council (CEC) recommended that there should be a statement in the NEO to ensure "that the objectives are satisfied by considering them in light of 'support for government policies on the environment and climate change'".[22] Similarly, Infigen

16 Alinta, Issues Paper submission, p. 7.

17 Infigen, Issues Paper submission, p. 2.

18 LYMMCo, Issues Paper submission, p. 16.

19 MEU, Issues Paper submission, pp. 23-24.

20 TEC, Issues Paper submission, p. 9.

21 TEC, Issues Paper submission, p. 2.

22 CEC, Issues Paper submission, pp. 5-6.

and Vestas suggested revisions to the NEO to address matters such as greenhouse gas reductions and the promotion of renewable or sustainable electricity generation.[23]

Commission's current views

The Commission continues to believe that the objective for transmission frameworks should be to ensure that investment and operational decisions across generation and transmission are optimised in a manner that minimises the total system costs faced by consumers.

The Commission notes that some of the additional objectives proposed by stakeholders may not be inconsistent with this. For instance, the promotion of competition in generation is likely to play a central role in cost minimisation. Equally, the facilitation of demand-side response and non-network options as substitutes for generation and transmission will be important in the achievement of overall economic efficiency.

While the Commission considers that many of the principles or subsidiary objectives proposed by stakeholders may have merit, the Commission does not intend to adopt any of these at this time. The Commission considers that, in many cases, these might act to prejudge or limit the outcome of the detailed work on elements of transmission frameworks that it is intended to progress.

Finally, the Commission notes that changes to the NEO itself are out of the scope of this review. This would instead be a matter for governments to consider. However, the Commission further notes that many of the stakeholders suggesting such amendments did acknowledge this.

3.2 Shaping and defining the role of transmission

Under the current NEM arrangements, TNSPs are responsible for meeting the current and forecast needs of load customers. Transmission augmentations are primarily undertaken to meet demand growth while maintaining compliance with reliability obligations to customers. TNSPs therefore have an interest in ensuring that sufficient power can be generated and transported to customers to meet total load, but few obligations in relation to specific load customers or to generators.

The Terms of Reference for the review require us to give consideration to the appropriate future role for transmission in providing efficient services to the competitive sectors of the NEM. In particular, we are to examine the nature, incentive properties and effectiveness of the existing access arrangements and alternative approaches to transmission service provision.

Consequently, in the Issues Paper, we asked about the appropriate future role of transmission in providing services to the competitive sectors of the NEM. We also asked what evidence there is, if any, to suggest that the existing service provided to facilitate the market, or the definition of this service, is inappropriate or insufficient.

23 Infigen, Issues Paper submission, p. 1; Vestas, Issues Paper submission, p. 3.

Stakeholder views

Stakeholder submissions to the Issues Paper revealed no consistent views about the overarching role to be played by transmission, even with regard to its role under existing frameworks.

Most stakeholders highlighted some form of role in facilitating secure and reliable supply to consumers, although few considered that this was the only role. One such view was expressed by SP AusNet, which commented that:

> "The physical role of transmission is clear: that is, to transport electricity from generation connection points to customers with access to energy supplies by connecting generation.[24]"

Another stakeholder to point to the physical role of transmission was International Power Australia (International Power), which considered that:

> "...the existing role of transmission is not to provide a service to generators, but to provide an economically-sized network as a whole. A TNSP is essentially established as an 'infrastructure provider' rather than a service provider. Or, put another way, a TNSP only has one 'customer', the electricity market, and only has service obligations to that 'customer'.[25]"

However, it was apparent from its submission that International Power considered that the absence of a defined service being provided to generators was inappropriate.[26]

International Power also considered that, in its existing capacity as an infrastructure provider, a TNSP is tasked with multiple roles, including: planner, developer, operator, information provider, and owner. International Power suggested that there would be a conflict between the 'owner' and the other roles since the incentive on TNSPs to maximise profit under a regulated revenue cap would mean minimising the costs of undertaking the other roles. International Power suggested that this would impinge on the performance of these roles.[27]

Other stakeholders considered that the role of transmission was twofold, although there was some disagreement as to whether these roles were equal or whether one was subordinate to the other. For instance, LYMMCo characterised these two aspects as being to facilitate consumption - to ensure that low cost energy produced in one location can be consumed in another to the determined reliability standards - and to facilitate production. However, it was clear from LYMMCo's submission that it did not consider that this perceived second role of providing a service to generation had been adequately met to date.[28]

24 SP AusNet, Issues Paper submission, p. 9.

25 International Power, Issues Paper submission, p. 9.

26 Ibid.

27 Ibid, p. 10.

28 LYMMCo, Issues Paper submission, p. 16.

In contrast, the MEU considered that the primary purpose of transmission is to deliver power from generators to large load centres, including distribution networks. It then characterised the promotion of competition between generators, so that generation is delivered to consumers at least cost, as being a secondary purpose.[29]

Grid Australia considered that there are at least three roles for transmission. It characterised these as being:

- a physical role - to transport energy from generators to directly connected customers or distribution connection points while maintaining system security;
- a financial (market facilitating) role - to facilitate trading between buyers (retailers and customers) and sellers (generators) and enable competition; and
- a market development role - to facilitate the connection of new generators and customers and, more generally, to support the growth of electricity demand.[30]

There was also little consensus from stakeholders as to any required changes. A number of generators suggested that there was a need to thoroughly consider the appropriate future role of transmission in providing services to the competitive sectors of the NEM. Of these, LYMMCo considered that transmission currently fails to satisfy participant requirements and does not support efficient outcomes for a number of reasons, mostly linked to the currently uncertain level of service provided to generators.[31]

The NGF commented, more generally, that:

> "While the NEM arrangements explicitly consider the needs of consumers and are driven by the desire to minimise total energy costs, the needs of individual generators who drive wholesale competition are not explicitly considered nor is the magnitude of the risk. This imbalance, considering the asymmetric risks faced by generators should transmission not be available, seems inappropriate."[32]

Some other stakeholders also agreed that the role of transmission should be reconsidered. For instance, Gallaugher suggested that the feasibility of moving to much broader competitive market model for the provision of transmission services should be investigated as this might lead to an improved allocation of market risk.[33]

However, other stakeholders questioned whether such changes would be appropriate. For example, EnergyAustralia considered that, if this implied that TNSPs would be required to manage risks associated with generator congestion, the exposure of a

29 MEU, Issues Paper submission, p. 26.

30 Grid Australia, Issues Paper submission, pp. 15-16.

31 LYMMCO, Issues Paper submission, p. 17.

32 NGF, Issues Paper submission, p. 5.

33 Gallaugher, Issues Paper submission, pp. 2-3.

regulated entity to risk may not be kept to a tolerable level.[34] Similarly, the Northern Group considered that:

> "A move away from a central focus on consumers, as it is expressed in the NEO, to 'the competitive sector' risks confusing the overarching objective of the NEM with the means of achieving that objective. Shifting the focus of services provided by TNSPs from consumers to the commercial sector will compromise the NEO's central focus."[35]

Others appeared to take a neutral view. SP AusNet agreed that any revision to the role of transmission in the market would represent a significant change, but equally considered that firmer access might be a major factor in generation investment decision making. It therefore concluded that:

> "...any proposal to revise the role of transmission in the market, or the definition of transmission services, would warrant careful consideration, development and assessment, to ensure that any changes would help align the incentives of generators and TNSPs, and therefore ultimately enhance the achievement of the national electricity objective."[36]

Finally, the DPI expressed support for the AEMC's approach of developing internally consistent reform packages which deliver a long term vision for the role of transmission.[37]

Commission's current views

The Commission notes the views expressed by stakeholders.

While the Commission believes that it is important to give high-level consideration to the role of transmission, the Commission also considers that such an assessment will be more meaningful if undertaken in combination with a more detailed examination of the key areas of transmission frameworks, as required by the Terms of Reference for the review.

However, in order to facilitate its further consideration under this work program, the Commission's initial view of the role of transmission is that it should be:

> "To provide services to competitive and regulated sectors of the electricity market in a manner that is in the long term interests of consumers of electricity."

As indicated, this role will be reassessed and potentially refined by the work undertaken during the remainder of the review. Consideration of the role of transmission will therefore not be progressed as a workstream in its own right, but will

34 EnergyAustralia, Issues Paper submission, p. 5.

35 Northern Group, Issues Paper submission, p.13.

36 SP AusNet, Issues Paper submission, p. 10.

37 DPI, Issues Paper submission, p. 3.

inform, and be informed by, the five workstreams that are discussed in the following five chapters. In particular, the nature of the services provided by transmission will form a central focus of the access workstream, and it is expected that the Commission's conclusions in this area will act to further specify the appropriate future role of transmission.

4 Nature of access

4.1 Introduction

This chapter covers the first workstream identified by the Commission for further consideration: the nature of access. Access arrangements represent a fundamental element of the service being provided by transmission to market participants and consumers.

The chapter firstly describes the nature of the issue, and then discusses the aspects of the issue that the Commission intends to consider further in the review. This structure is used in each of the following chapters.

4.2 What is the issue?

4.2.1 Level of transmission service to generators

Currently in the NEM, a generator's 'right' to use the transmission network depends on whether it is dispatched by AEMO. If the network is congested, generators face a risk of not being dispatched - being constrained-off the system - or, in some cases, being constrained-on.[38] In this paper, this level of service is referred to as 'non-firm' access.

The Commission considers that it is important to differentiate between the service provided to generators for access *to the transmission network* and the service *across the transmission network* to the Regional Reference Node (RRN). TNSPs have obligations to connect generators to the network - or to provide 'open' access. However, there are no functioning obligations on TNSPs to provide access rights for use of the deeper network.[39] Generators therefore have a limited ability to manage their exposure to dispatch uncertainty.

Generators may choose to fund augmentations to the shared transmission network in order to reduce congestion and the risk of constraints. However, generators receive no exclusive 'right' to the use of such augmentations, and the benefits of the reinforcement may accrue to other generators.

The lack of certainty for generators over dispatch outcomes can impact financial markets, in that it may limit whether generators can continue to meet their contractual obligations. As a result, generators may reduce the volume of contracts offered, reducing liquidity in the contract market, or factor in a risk premium, resulting in higher contract prices. This, in turn, will be reflected in higher prices to consumers.

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38 This is discussed further in chapter 6.

39 Some stakeholders have noted that they disagree with the Commission's previous characterisations of the access arrangements applying to generators in the NEM. This is discussed later in this chapter.

Dispatch uncertainty can also affect new investment decisions, as investment financing is more difficult to obtain for projects exposed to variable, uncertain revenue streams. As a result, investors may include a risk premium, increasing the cost of new investments or, potentially, deterring entry. These risks were highlighted by a number of stakeholders in response to the Issues Paper.[40]

Concepts associated with alternative levels of transmission service

An alternative to the existing non-firm service would be to provide generators with access rights. Access rights for generators are often described as being either 'physical' or 'financial' (or, potentially, a combination of the two):

- A physical right or service would ensure that some defined level of transmission capacity was made available to the generator in planning timescales to facilitate its dispatch. However, the dispatch of the generator in operational timeframes would not be guaranteed and the generator would not receive compensation if the transmission capacity was unavailable.
- A financial right would ensure that the generator was compensated in the event that it was not able to be dispatched at the level of the agreed right. In nodally priced markets, such rights can be provided through the use of the settlement residues.[41]

The availability of access rights or an enhanced service would offer a means of managing or mitigating dispatch uncertainty. However, such a regime can often imply that the associated risks were transferred to TNSPs and/or consumers. To date this has not been considered appropriate in the NEM.

4.2.2 Level of transmission service to load

All TNSPs in the NEM have obligations to meet transmission reliability standards, which govern the service provided to load. These standards generally ensure a level of redundancy on the system, implying that the supply of power to total load will be robust in the event of a certain level of contingencies. Load as a whole can therefore be considered to receive some level of implied access 'right'.

However, transmission reliability standards are largely defined in jurisdictional instruments, and therefore differ (sometimes significantly) between regions. At the request of the MCE, the Commission undertook a review of transmission reliability standards in the NEM, with a view to developing a national framework for network

40 AEMO, Issues Paper submission, p. 18; AGL, Issues Paper submission, p. 11; DPI, Issus Paper submission, pp. 2-3; LYMMCo, Issues Paper submission, p. 10.

41 This is discussed in more detail in section 4.3.5.

reliability. The MCE has yet to respond to the Commission's recommendations for a national framework.[42]

While these standards require delivery of a specified overall service level to customers as a group, there are few obligations on TNSPs in relation to the service provided to individual demand customers (although some may exist in individual connection agreements for larger users).

4.3 Areas for further consideration

In light of submissions to the Issues Paper, the Commission has identified five key areas for further consideration in the review. These are:

- differing interpretations of current arrangements;
- factors perceived as exacerbating issues associated with the absence of generator access rights;
- potential reliability standards for generation;
- selective negotiated or enhanced rights for generators; and
- the potential for a financial access rights regime.

The following sections consider each of these areas in turn.

4.3.1 Differing interpretations of current arrangements

Some stakeholders highlighted that they disagreed with the Commission's characterisation in the Issues Paper of the access arrangements applying to generators in the NEM, or noted that there is at least a lack of clarity in the Rules regarding access rights for generators.[43]

These stakeholders made reference to the Australian Energy Market Agreement (AEMA), a number of consultation and determination documents during the development of the NEM[44] and certain clauses in the Rules. The Commission understands that two separate, but related, arguments are being advanced, which are that:

- the existing non-firm nature of access in the NEM is not what was intended when the NEM was originally developed; and that

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42 AEMC 2008, *Transmission Reliability Standards Review*, Final Report to MCE, 30 September 2008, Sydney, and AEMC 2010, *Transmission Reliability Standards Review*, Updated Final Report, 3 November 2010, Sydney.

43 AGL, Issues Paper submission, p. 2; LYMMCo, Issues Paper submission, p. 9-10.

44 See, for instance: ACCC, Decision, Application for acceptance, National Electricity Market Access Code, 16 September 1998.

- the non-firm access regime is a result of the failure to follow a number of provisions in the Rules, primarily relating to the connection of new generators.

In particular, the Commission understands that it is contended that the Rules provide for access certainty to a generator through new entrant generators paying to augment the shared network such that an 'agreed transfer capacity' (specified in the connection agreement with the TNSP) for the first generator is maintained.[45] The suggestion appears to be that this would essentially provide a physical access right for generators.

The stakeholders raising this matter as an issue all have generation interests in Victoria. It is not clear whether generators in other jurisdictions are of the understanding that they have agreed transfer capabilities.

In any event, the relevant stakeholders note that generator access in the NEM is not, in practice, 'protected' in the manner discussed above. One stakeholder suggested a number of reasons for this, including that the relevant Rules provisions lack clarity.[46]

The Commission also notes that the AEMA reference is to "access to energy infrastructure".[47] As discussed earlier, the Commission considers that, with regards to electricity transmission, this is reflected in the open access nature of connections to the network, rather than in any right of access to the RRN.

Operation of Rule 5.4A

In addition to the above, Rule 5.4A appears to provide a mechanism for generators to obtain financial access rights in the NEM.[48] The Commission has previously concluded that this provision cannot work in practice as it is currently drafted. If a TNSP were to negotiate an enhanced level of service with a connecting generator under the provisions of Rule 5.4A, that TNSP would have no way of managing its exposure to the associated risks, other than by recovering costs from the generator itself. There would also be difficulties associated with identifying the "causer" of the reduced access.[49]

While some support for the Commission investigating how to implement Rule 5.4A or a similar mechanism was expressed,[50] no stakeholders in submissions to the Issues Paper suggested that Rule 5.4A was workable in its current form. One stakeholder

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45 AGL, Issues Paper submission, p. 27 & pp. 33-35; International Power, Issues Paper submission, pp. 37-39.

46 AGL, Issues Paper submission, p. 27.

47 See: Australian Energy Market Agreement, as amended 2 July 2009, p. 20.

48 In particular, clause 5.4A(h)(1) provides for the TNSP to pay compensation to the generator in the event that it is constrained-off or -on.

49 AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, 30 September 2009, Sydney, p. 35.

50 Alinta, Issues Paper submission, p. 23; LYMMCo, Issues Paper submission, p. 28; NGF, Issues Paper submission, p. 7.

noted that "there is as yet no means of implementing this",[51] while another suggested that "ambiguities in the NER have undermined 5.4A".[52]

Commission's current views

The Commission notes the issues presented by stakeholders relating to current Rule provisions. However, the Commission considers that any changes to the non-firm access arrangements in the NEM should best be considered from first principles rather than attempting to structure them to fit certain provisions in the Rules which might be ambiguous, unworkable and contentious, and which would not result in a coherent regime.

More generally, the Commission considers that the inability of all stakeholders to agree on the nature of the existing arrangements is a clear indication that this is an area that would benefit from further consideration. Even if the Commission were to recommend that no material changes should be made to the non-firm access regime, it is likely that there would be merit in a clearer and more prescriptive articulation of this in the Rules.

4.3.2 Factors perceived as exacerbating issues associated with the absence of generator access rights

A number of stakeholders noted in submissions to the Issues Paper that there was a potential risk that TNSPs could fail to invest in an efficient or timely manner.[53]This might lead to an inappropriately high level of congestion and therefore a greater amount of dispatch uncertainty to be managed by generators compared to that which would result if the current regime was operating as intended.

In particular, many of the reasons put forward for this potentially being the case related to perceived issues with the RIT-T. It was suggested that there are difficulties in quantifying market benefits (especially competition benefits and option values) under the RIT-T which would mean that fewer projects would be likely to pass the test than should be the case.[54] More broadly, it was noted that the RIT-T process does not act to ensure that TNSPs construct all projects that are economic, rather that it only prevents TNSPs constructing projects that are uneconomic.[55]

Some stakeholders also highlighted a particular issue with possible under-investment in interconnectors, due both to the difficulties in justifying these solely on market benefits grounds (reliability standards generally do not apply to inter-regional

51 AGL, Issues Paper submission, p. 27.

52 NGF, Issues Paper submission, p. 7.

53 Brookfield, Issues Paper submission, p. 5; CEC, Issues Paper submission, p. 6; DPI, Issues Paper submission, p. 8; Infigen, Issues Paper submission, p. 6; International Power, Issues Paper submission, p. 19; LYMMCo, Issues Paper submission, p. 23; Origin, Issues Paper submission, p. 6; TRUenergy, Issues Paper submission, p. 2.

54 EUAA, Issues Paper submission, p. 12; Infigen, Issues Paper submission, p. 5; LYMMCo, Issues Paper submission, p. 21; NGF, Issues Paper submission, p. 8; Origin, Issues Paper submission, p. 6; TRUenergy, Issues Paper submission, p. 2

55 AEMO, Issues Paper submission, p. 9; International Power, Issues Paper submission, p. 19

investments) and because of unclear responsibilities for inter-regional transmission planning.[56]

However, other stakeholders did not agree with these potential issues, in particular noting that, as long as the regulatory rate of return is sufficient and/or the incentives for good service performance are attractive, TNSPs should be willing to invest in projects justified on market benefits grounds. The roles of the NTNDP and the LRPP in facilitating national co-ordination and providing moral suasion were also noted.[57]

In Victoria, a specific issue raised was that of the prevailing jurisdictional transmission reliability standards. It was suggested that the probabilistic planning standard applied in that state, which permits investment only on economic grounds and does not provide for a deterministic level of redundancy, results in a lesser level of transmission capacity than is the case in other states. This might act to increase the level of congestion and dispatch uncertainty for generators.[58]

Commission's current views

The Commission notes the views discussed above. Although the issues raised clearly interact with those relating to the service being provided by transmission, the Commission intends to consider them as part of the planning workstream. They are therefore discussed further in chapter 7 of this document.

4.3.3 Reliability standards for generation

In response to the Issues Paper, a number of stakeholders suggested that the Commission should investigate the possibility of introducing transmission reliability standards for generation.[59]

In a similar manner to transmission reliability standards for load, these standards would aim to ensure that a certain level of transmission capacity was provided for generators in planning timescales. This would represent a form of defined physical service (although, as noted earlier, the dispatch of the generator in operational timeframes would not be guaranteed and the generator would not receive compensation if the transmission capacity was unavailable).

Two stakeholders, International Power and LYMMCo, provided detailed discussion of how such a regime might work.[60] The models presented were based around TNSPs

56 International Power, Issues Paper submission, p. 18; MEU, Issues Paper submission, p. 27; TRUenergy, Issues Paper submission, p. 4.

57 Grid Australia, Issues Paper submission, p. 21; Northern Group, Issues Paper submission, p. 18.

58 Alinta, Issues Paper submission, p. 14; LYMMCo, Issues Paper submission, p. 8; Northern Group, Issues Paper submission, p. 16; TRUenergy, Issues Paper submission, p. 2.

59 AEMO, Issues Paper submission, p. 28; AGL, Issues Paper submission, p. 25; Grid Australia, Issues Paper submission, p. 12; Infigen, Issues Paper submission, p. 7; International Power, Issues Paper submission, p. 17; LYMMCo, Issues Paper submission, p. 28.

60 International Power, Issues Paper submission, pp. 17, 20-21, 27-29; LYMMCo, Issues Paper submission, pp. 37-41.

planning to ensure that a generator would have the ability to evacuate its full generation capacity (or, alternatively, a specified proportion of its capacity) under specified planning conditions (or for a specified percentage of the time under these conditions). The conditions would include assumptions about plant availability and bidding, about the level of demand (for instance, peak demand at a 10% Probability of Exceedance level) and about network conditions (which can be expressed in deterministic terms, such as 'N', 'N–1' or 'N–2').[61] It was also suggested that the zone over which the standard would be assessed would require consideration.[62]

The Commission notes that a fundamental implementation issue would be defining these parameters such that the standard was set at an efficient level. LYMMCo and the Northern Group both highlighted the example of the market in Alberta, Canada, where "access rights are maintained implicitly via a high-level policy target that sets an overall network congestion standard".[63] However, both of these stakeholders suggested that the standard in Alberta was calibrated such that the costs of the additional transmission were likely to significantly exceed the resulting benefits.[64]

The Commission also notes that in its *Review of Energy Market Frameworks in light of Climate Change Policies*, it found that the 'unconstrained' transmission planning approach employed in Western Australia's South West Interconnected System was likely to result in inefficient over-investment in the transmission network.[65]

New entry and competition

In developing a transmission reliability standard for generation, it would also be necessary to resolve how new entrant generators would be accommodated in situations where the capacity of the existing transmission network was insufficient for the reliability standard to be maintained. One option would be not to connect the new entrant until the network had been reinforced to meet the new capacity requirement. However, experience in other markets suggests that such transmission augmentations take significantly longer to construct than new power stations, and this has led to connection 'queues' in those markets. This approach could also affect the level of competition in the wholesale market.

An alternative would be to allow the new entrant to connect and the standard to be breached temporarily until such time as the required transmission reinforcements

61 It was noted that when network capacity fell below that implied by these conditions, congestion might constrain generators below their defined access level. In this sense, the access rights implied by the a reliability standard would not be firm and some residual constraint risk would remain. However, it was suggested that "if the defined access planning conditions are defined appropriately, this risk will be moderate and manageable, unlike the status quo". International Power, Issues Paper submission, p. 29.

62 It was suggested that measuring compliance with the standard over a region could lead to a small number of generators facing the bulk of the congestion. LYMMCo, Issues Paper submission, p. 39.

63 Northern Group, Issues Paper submission, p. 28.

64 LYMMCo, Issues Paper submission, p. 38; Northern Group, Issues Paper submission, p. 28.

65 AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, 30 September 2009, Sydney, p. 140.

could be completed (or existing generation capacity was retired). Under this option it would be necessary to consider whether any obligations or incentives would be needed to ensure that compliance was restored in a timely manner by the TNSP.[66] This would also imply that all generators would be faced with a reduced level of implied access during this period. Where there were significant levels of new entry, this period might be prolonged.

Finally, a further option would essentially be to have two levels of implied 'access rights'. Under this model, where new entrants were connecting generation before the TNSP could restore compliance with the transmission reliability standard, any constraint risk would first be targeted at these generators. That is to say that these new entrant power stations would be constrained-off the network in preference to other generating plant. The implied access rights of incumbents would therefore be protected.[67] Once the required transmission augmentation had been completed, the higher level of access would be made available to the new entrants.

Again, under such an option, there would be issues to consider in terms of competition and potential discrimination. However, if the provision of the higher level of access was linked to payment of a charge, it is possible that some participants may find it beneficial to opt for the lower level of access.

Charging implications

While the investment in the shared network required under a transmission reliability standard for generation could be funded directly by consumers, consideration would need to be given as to whether it was appropriate for transmission charges to be levied on generators.

It seems likely that a reliability standard for generation set at any level would result in the provision of a greater amount of transmission assets than would be deemed economic under current frameworks. It is therefore not clear that these should be funded by consumers. However, this might also suggest that, even if the additional costs were funded by generators, mandatory participation for generators in such a scheme might result in an uneconomic level of costs being passed through by generators to consumers. In considering this matter further, it would be important to understand the benefits that generators would accrue from the reduced constraint risk that would result and the extent to which these benefits would flow through to consumers.

Given the direct linkage between generator entry and transmission investment under a transmission reliability standard for generation, consideration of a locational signal to reflect the costs of the transmission investment would be required. There would be a significant risk of inefficient outcomes if the variation in the costs of transmission investment driven by the location of the generator was not factored into generator decision making. If generator transmission charges were deemed necessary, a broad

66 Noting that it might be concluded that existing incentives on TNSPs were sufficient.

67 Although this would still be subject to the congestion not exceeding the level that was planned to.

range of further issues would need to be considered. Many of these are discussed in the next chapter.

The Commission notes that a model under which a new entrant was required to pay directly for any transmission augmentations required to restore compliance with the reliability standard on a mandatory basis would represent a deep connection charge. The Commission intends to give further consideration to such models in this review, although it has previously noted concerns with deep connection charges with regards to barriers to entry and first mover disadvantages.[68]

Governance

As noted earlier, transmission reliability standards for load are generally governed at a jurisdictional level.[69] This allows the level of reliability provided by transmission to consumers within a jurisdiction to be determined by a decision-maker specific to that jurisdiction.[70]

However, the need to ensure competitive neutrality between generators across the NEM might mean that it was most appropriate to define a transmission reliability standard for generation on a NEM-wide basis. Consideration would therefore need to be given as to how this should be achieved.

It would also be necessary to assess the extent to which any generation transmission reliability standard was consistent with the various jurisdictional transmission reliability standards for load. In particular, it is not clear that the models discussed above would be consistent with the probabilistic planning approach currently employed in Victoria, where transmission augmentations are made solely on an economic cost-benefit basis.[71]

Commission's current views

The Commission is of the view that the potential for a transmission reliability standard for generation should be given further consideration in the review. In particular, such a

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68 AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, 30 September 2009, Sydney, p. 262.

69 The level of transmission reliability in Victoria results from the use of probabilistic planning by AEMO, as specified by section 50F of the NEL.

70 The Commission has made recommendations to the MCE for a national framework to promote consistency and transparency in transmission reliability standards. Under this framework, standards would be determined by an independent jurisdictional body, unless the jurisdiction chose to have the determination made by a national decision-maker. See: AEMC 2008, *Transmission Reliability Standards Review*, Final Report to MCE, 30 September 2008, Sydney; and AEMC 2010, *Transmission Reliability Standards Review*, Updated Final Report, 3 November 2010, Sydney.

71 One stakeholder raised the issue of whether augmentations justified on an economic basis should be made "over the top" of the level of capacity required under a transmission reliability standard for generation, as this might lead to a higher level of access for a generator or generators. However, the Commission understands that this comment was made in reference to augmentations justified under the RIT-T on the basis of market benefits across the NEM, rather than directly with reference to Victoria. International Power, Issues Paper submission, p. 21.

regime might be easier to implement given the architecture of the NEM than a model of firm financial rights, for instance. (This is discussed further later in this chapter.)

However, as indicated above, there would be significant issues associated with such a proposal, both in its justification at a high level but also at a more detailed implementation level. Consideration would also be need to be given to transitional arrangements for existing generation given the current level of transmission capacity in the NEM.

4.3.4 Selective negotiated or enhanced rights for generators

In the Issues Paper, the Commission asked whether it would be appropriate for generators and load to have the option of obtaining an enhanced level of transmission service. Many stakeholders indicated that they considered that an option of an enhanced level of service for generators should be explored, although generally only if this was paid for by the generator in question.[72]

However, in their responses to this question, a number of stakeholders sought firstly to define a new level of service against which a further enhanced level could be considered.[73] The result was that it was sometimes unclear exactly what level of enhanced service was being discussed. The intent of the question in the Issues Paper was to canvass views as to the possibility of obtaining an enhanced level of transmission service on a selective basis as compared to the existing non-firm access regime.

Arguments for the introduction of enhanced rights included: that the ability to manage constraint risk would remove a barrier to entry;[74] that competition and the liquidity of contract markets may be enhanced;[75] that rights would assist in congestion management;[76] and that total system costs would be minimised in that generators would be able to choose the level of congestion they wished to face.[77]

However, a number of stakeholders did not consider that making available an option of an enhanced level of service would be appropriate.[78] These parties suggested that: the current regime provides appropriate TNSP behaviours without exposing them to market risk;[79] that it would be difficult to provide differing levels of service to different

72 AGL, Issues Paper submission, p. 2; Alinta, Issues Paper submission, p. 12; CEC, Issues Paper submission, p. 6; EUAA, Issues Paper submission, p. 18; Gallaugher, Issues Paper submission, p. 4; International Power, Issues Paper submission, p. 27; LYMMCo, Issues Paper submission, p. 28; MEU, Issues Paper submission, p. 36; TRUenergy, Issues Paper submission, p. 6.

73 AGL, Issues Paper submission, p. 25; International Power, Issues Paper submission, p. 27; LYMMCo, Issues Paper submission, p. 28.

74 AGL, Issues Paper submission, p. 2.

75 EUAA, Issues Paper submission, p. 7; LYMMCo, Issues Paper submission, p. 28.

76 AGL, Issues Paper submission, p. 2.

77 AGL, Issues Paper submission, p. 5; LYMMCo, Issues Paper submission, p. 28.

78 Energy Australia, Issues Paper submission, p. 2; ENA, Issues Paper submission, p. 2.

79 Energy Australia, Issues Paper submission, p. 2.

customers using shared infrastructure;[80] that risk would be transferred to TNSPs (and, by extension, consumers) and that TNSPs were unlikely to manage this risk well;[81] and that a number of factors impacting on available transfer capability are outside the control of TNSPs.[82]

Two stakeholders, Origin and the Northern Group, specifically discussed the benefits of the existing non-firm access arrangements. These stakeholders considered that the current regime "promotes competition between different types of generation plant and does not discriminate irrespective of fuel type or on the basis of new entry or incumbency",[83] and that it "may have encouraged generators to locate where there is excess transmission capacity and deferred generation investment in constrained parts of the network".[84] It was further contended that there is no evidence that the current non-firm access regime has discouraged generation investment.[85]

Models suggested by stakeholders

A number of different models were proposed by stakeholders, and some of those which would be broadly applied across the market are discussed in the previous and following sections. The application of both physical and financial rights on a negotiated basis was also discussed, including the possibility of TNSPs paying compensation to constrained generation, albeit perhaps not with full market exposure.[86] In particular, a number of stakeholders considered that some form of enhanced service should be provided to generators funding augmentations to the shared network.[87] It was also suggested that any access rights should be tradeable.[88]

However, some stakeholders noted potential problems with the application of physical or financial rights on a negotiated basis. In respect of physical rights, it was suggested that the provision of defined rights to one party would be difficult in that this may negatively impact on other parties.[89] Similarly, it was highlighted that ongoing investment would be likely to be required to maintain the level of access provided.[90] The Commission notes that even if a party obtaining firm physical access rights funded the original investment required, it is likely that further investments would be required

80 Energy Australia, Issues Paper submission, p. 8; ENA, Issues Paper submission, p. 2.

81 EUAA, Issues Paper submission, p. 7.

82 Grid Australia, Issues Paper submission, p. 11.

83 Origin, Issues Paper submission, p. 8.

84 Northern Group, Issues Paper submission, p. 26.

85 Ibid.

86 AGL, Issues Paper submission, p. 16; Alinta, Issues Paper submission, p. 21; TRUenergy, Issues Paper submission, p. 6.

87 AGL, Issues Paper submission, p. 7; Infigen, Issues Paper submission, p. 3; MEU, Issues Paper submission, p. 36; TRUenergy, Issues Paper submission, p. 7.

88 AGL, Issues Paper submission, p. 5; Alinta, Issues Paper submission, p. 22; EUAA, Issues Paper submission, p. 18; International Power, Issues Paper submission, p. 26.

89 Energy Australia, Issues Paper submission, p. 2; ENA, Issues Paper submission, p. 2; Northern Generators, Issues Paper submission, p. 26.

90 Energy Australia, Issues Paper submission, p. 8.

to maintain the access right in the face of subsequent generation entry. If these later generators did not elect to purchase firm access rights, it is not clear how these investments would be funded.

In respect of financial rights, EnergyAustralia and the Northern Group queried whether it was appropriate to expose NSPs to market trading outcomes and suggested that firm access rights result in material dynamic inefficiencies.[91] It was noted that requiring TNSPs to manage such risks would fundamentally change the existing role of transmission, with other implications, including cost impacts. With respect to the latter argument, the Commission understands that the suggestion is that, due to the protection against constraint risk provided by firm rights, generators may make costlier locational decisions than they would under a non-firm access regime. However, the Commission notes that the possibility of charges associated with the access rights being set on a locational basis may provide alternative locational signals. This is discussed further in the next chapter.

Commission's current views

The Commission notes the views expressed by stakeholders, and intends to give further consideration to developing models that would allow generators to pay for an enhanced level of access.

The Commission also notes the concerns of some stakeholders that, in practice, implementing such a regime on a selective or negotiated basis may be problematic. In particular, it might be difficult to develop arrangements that provide enhanced rights to generators opting in to a scheme without having a detrimental effect on the level of service provided to other generators.

4.3.5 Financial access rights regime

The Commission notes that, internationally, financial access rights are more usually offered as part of market-wide schemes, rather than negotiated on an individual basis.

A number of submissions discussed models involving either the widespread or mandatory introduction of financial access rights for generation, including references to nodally priced markets with Financial Transmission Rights (FTRs) in the US.[92]

Aside from the potential benefits of access rights already noted in terms of providing additional certainty to generators in planning their investments, it was suggested by the DPI that the sale of firm access rights could provide additional, robust information to network planners on the demand for network capacity which could be used when making decisions on whether to augment the network.[93]

91 Energy Australia, Issues Paper submission, p. 2; Northern Group, Issues Paper submission, p. 27.

92 DPI, Issues Paper submission, p. 5; LYMMCo, Issues Paper submission, p. 28; Northern Group, Issues Paper submission, p. 28.

93 DPI, Issues Paper submission, p. 5.

Potential use of settlement residues

As has been noted, in nodally priced markets FTRs can be provided through the use of settlement residues.

Box 4.1 Settlement residues

Generators do not currently face price risk when trading intra-regionally because a single price is determined at the RRN and applied across that region. However, price risk (or 'basis risk') may arise when generators trade between regions. One way to reduce this risk is to purchase units to the Inter-Regional Settlement Residues (IRSRs) that result when prices between regions separate.[94] These IRSR units are sold at the Settlement Residue Auctions (SRA), which are held every quarter.

Where generators trade across regions, their revenue therefore may comprise two elements. The first is the 'pricing element', which is simply the volume they are dispatched for multiplied by their Regional Reference Price (RRP). The second element is the 'risk management element' which is derived from any IRSR units the generator has successfully purchased at auction.

It is important to note that IRSR units do not provide a perfect hedge for inter-regional basis risk. For example, where the capacity of the interconnector is lower than was assumed for the purpose of the SRA, or where counter-price flows occur, the value of the IRSR units are scaled down and so generators continue to be exposed to a level of basis risk.

Within a region, generators receive (and loads pay) the same price so there is no explicit intra-regional price separation. However, each local node has an implicit price or 'shadow price'. Congestion may cause the shadow price and the RRP to diverge. Therefore we can conceptually consider residues arising from intra-regional price separation between the shadow price at a local node and the RRP.

These conceptual residues arising from intra-regional price separation can be considered to be allocated to generators that are dispatched and provide a perfect hedge for generators trading within a region.

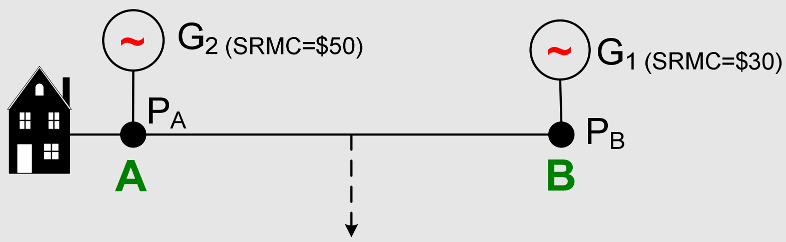
To see this, we can consider a generator’s revenue comprising two elements as in the inter-regional example. The price component is equal to the amount they are dispatched for multiplied by the shadow price at their local node. The risk management element is equal to the amount they are dispatched for multiplied by the difference between the shadow price and the RRP. Because local nodes are not explicitly priced, in practice this reduces to dispatched generation multiplied by the RRP. An example is provided in Box 4.2.

94 The value of these residues is equal to the price difference between the regions multiplied by the flow between regions.

As described in Box 4.1, a generator's revenue effectively comprises a pricing element and a risk management element that may be derived from settlement residues. In the NEM all generators within a region are exposed to a single regional reference price, which means that those generators that are dispatched receive all of the residues.

Box 4.2 Allocation of conceptual intra-regional settlement residues

The diagram below demonstrates how the conceptual settlement residues arising from implicit intra-regional price separation are currently allocated. The example assumes no losses and that generators bid at their short run marginal cost (SRMC). The generator at node B (G_1) has a SRMC of \$30 and capacity of 200 MW. The generator at node A (G_2) has a SRMC of \$50 and 100 MW of capacity. All generators receive the regional reference price which is set at node A. The network has a constraint of 100 MW flowing from B to A.



$$\text{Constraint}_{AB} = G_1 \leq 100$$

In the example, when demand at node A reaches 101 MW there is a constraint on the network. This means that demand cannot be met with the cheaper generation from G_1. G_2 must be dispatched for 1 MW. This causes (implicit) price separation between the two nodes (P_A=\$50, P_B=\$30) and so (conceptual) settlement residues arise equal to the price difference multiplied by the flows on the line (SR=(\$50-\$30)*100=\$2,000).

The two generators receive the following amounts, separated into the conceptual pricing element (local price multiplied by volume dispatched) and risk management element (the settlement residue):

	Local price	**Residue**	**Total**
G_1	\$30 x 100MW = \$3,000	\$20 x 100MW = \$2,000	\$5,000
G_2	\$50 x 1MW = \$50	\$0 x 1MW = \$0	\$50

This is consistent with the total amount paid by load (\$50 x 101MW = \$5,050).

In markets where generators are exposed to their local (or nodal) price, the residues can be made available as FTRs to provide a hedge against basis risk, in the same way that IRSR units are auctioned in the NEM as a hedge (albeit a partial and uncertain hedge) against inter-regional basis risk. Generators purchasing FTRs would also be protected against dispatch risk, because they would receive the settlement residues regardless of whether or not they were dispatched.

Relevant experience in US markets

While a FTR regime might offer benefits in terms of increased certainty to generators able to secure access rights, the Northern Group, in its submission, highlighted difficulties observed from the practical application of such schemes in a variety of US markets.[95]

In particular, it was noted that the settlement residues available will vary by trading interval, and depend on the state of the network. If FTRs are to be 'self financing', the rights made available would have to be 'simultaneously feasible'. It was suggested that this would require the rights made available to be defined very conservatively so that they would only compensate the holder for congestion in a narrow set of system conditions. This is because they would need to take account of prevailing network conditions, such as contingencies, network deratings, and forced or planned outages. It was contended that in the PJM market[96] FTRs have provided only a very poor match of congestion costs.[97]

Over-estimating the network capacity on which rights are based would lead to settlement residues being insufficient to support the rights allocated, potentially requiring uplift payments to be levied on customers to recover the shortfall. This approach, which therefore directly exposes customers to additional liabilities, is one which has been taken in the New York wholesale market.[98]

Finally, the Northern Group also raised issues with the durability of FTRs, in that they are generally reviewed and reconfigured annually to ensure that they match the evolving physical capability of the network. It was suggested that FTRs can, and often are, downrated in the course of such assessments, and that complex and contentious reallocation processes therefore take place annually in all US nodal markets.[99]

Recent experience in Great Britain

Reference was also made by the Northern Group to access rights granted to generators in Great Britain, with the suggestion being made that these could be categorised as 'physical'.[100] The Commission notes that the generator access rights made available in the British market have, until recently, had both physical and financial elements. While generators received financial compensation for being constrained-off or -on the system, the requirement for a defined level of network reinforcement to be completed before the connection of new generator ensured that the physical supply of simultaneously feasible rights was increased commensurately with the financial rights issued.

95 Northern Group, Issues Paper submission, p. 28.

96 The PJM market has evolved from an initial Pennsylvania, New Jersey and Maryland base to encompass 13 US states as well as the District of Columbia.

97 Northern Group, Issues Paper submission, p. 28.

98 Ibid.

99 Ibid.

100 Northern Group, Issues Paper submission, p. 27.

However, recent reforms to access arrangements in Britain mean that access rights are now solely financial. Under these reforms, the system operator is compelled to release financial rights to new entrant generators, even if the associated physical increase in capacity has not been completed. The eligibility of all generation for financial rights, and therefore compensation for being constrained-on or -off, is likely to lead to consumers underwriting a significantly increased level of congestion risk.

Institutional arrangements

In addition to the practical difficulties associated with a firm access rights regime highlighted above, the Commission notes that a particular challenge in applying such arrangements in the NEM would be the identification of an appropriate counter-party to issue the rights.

In its submission, Grid Australia suggested that there are a broad range of factors that affect the real time transfer capacity of the transmission network. It therefore considered it would not be reasonable to expose TNSPs to congestion risk (or, at least, to the full value of this). Grid Australia also highlighted that AEMO, as a not-for-profit body, would not be in a position to bear this risk either.[101]

As a consequence, while it might be possible to introduce a self-financing FTR regime into the NEM, implementation of a regime of fully firm access rights would be more problematic. This is because such arrangements would be likely to require an additional source of revenue, such as an uplift charge on consumers. It would consequently be desirable to incentivise the body issuing the access rights to minimise these uplift charges. However, as noted, the current division of responsibilities between system operation and network provision would make the implementation of such incentives in the NEM more complex as compared to a situation where there is a single, integrated entity managing all the variables that impact on transmission system capacity. Equally, AEMO's not-for-profit status would also be inconsistent with the application of financial incentives.

Commission's current views

The Commission notes that there is a wide body of international experience to draw upon when considering the introduction of financial access rights. The Commission also notes the benefits that generators might derive from such a scheme and the additional benefits that could result in terms of market signals to be used as input for network planning.

However, the Commission further notes that such schemes are complex, and may be costly to implement. The introduction of financial access rights would represent a major change to the NEM market arrangements and, in particular, might require changes to the institutional arrangements in the NEM. There would therefore be a significant number of issues to consider in assessing the costs and benefits of any potential move to such a model.

101 Grid Australia, Issues Paper submission, p. 12.

5 Network charging

5.1 Introduction

This chapter discusses the network charging workstream identified by the Commission for further consideration. There is a strong linkage between the service being provided and the changes levied for its provision, as has been discussed.

The chapter outlines the issue and then discusses the aspects of it that the Commission intends to consider further in the review.

5.2 What is the issue?

The Pricing Principles for prescribed transmission services in Chapter 6A of the Rules require that the costs of the prescribed shared transmission network are to be recovered solely from load. As generators pay charges relating only to the cost of their immediate connection to the shared transmission network through a negotiated transmission service, the charging regime for generation can be characterised as a 'shallow' connection charging approach.

The combination of shallow connection charges and the recovery of network costs from load has the effect that generators, unlike demand customers, do not see any signal of the costs they impose on the shared network through their locational decision. Load, including large demand customers, is therefore treated differently to generation, and faces different signals.

The Commission has previously expressed concern that the absence of a price signal to generators of the impact of their locational decisions on transmission network costs may result in inefficient overall locational decisions that increase costs unnecessarily.[102]

There are a range of factors that influence the locational decisions made by generators, including access to fuel sources, the costs of transmission losses and the risk of constraints. However, generator proponents currently see no explicit price signal of the costs of any associated network augmentation (beyond directly incurred connection costs). This lack of price signal means that trade-offs between the costs of transmission and the costs of generation (potentially including the costs of alternatives to electricity transmission, such as gas pipeline costs) may not be appropriately made. However, the extent to which this will have an impact on efficiency will depend on the materiality of the associated network costs as a proportion of the total costs incurred by the generator.

Poor locational decisions can also impact on existing generators' trading risks, in that new entrants may connect in parts of the network that will impose costs for existing

102 AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, Sydney, p. 28.

generators. Where a new entrant's locational decision increases network congestion, generators may face greater dispatch uncertainty. This increased uncertainty can reduce liquidity in the contract market or lead to higher contract prices, and therefore increase costs to consumers. These issues are discussed further in the previous and following chapters.

Stakeholder views

In response to the Issues Paper, a large number of stakeholders expressed some level of agreement that a greater signal of location specific costs was required for generators.[103] In particular, some stakeholders considered that certain generators had sited in inefficient locations. The examples provided included Kogan Creek, Uranquinty and wind generation in the south-east of South Australia.[104]

However, a number of stakeholders considered that the levying of a transmission charge on generators should be linked to some form of increased service that would provide protection against additional congestion imposed by later entrants.[105]

In contrast, some other stakeholders considered either that an additional locational signal was not required or that the case had yet to be made conclusively.[106] There was also significant debate about the form of any signal, in particular whether it should be applied to all generation or just to new entrants.[107]

5.3 Areas for further consideration

In light of the stakeholder response noted above, the Commission has identified the following areas for further consideration in the review, which are elaborated on in the sections below:

103 AEMO, Issues Paper submission, p. 18; AER, Issues Paper submission, p. 12; AGL, Issues Paper submission, p. 5; Alinta, Issues Paper submission, p. 21; DPI, Issues Paper submission, p. 10, EnergyAustralia, Issues Paper submission, p. 3; ENA, Issues Paper submission, p. 2; EUAA, Issues Paper submission, p. 11; Gallaugher, Issues Paper submission, p. 4; Govt of SA, Issues Paper submission, p. 2; Grid Australia, Issues Paper submission, p. 22; Hydro Tasmania, Issues Paper submission, p. 6; International Power, Issues Paper submission, p. 8; MEU, Issues Paper submission, p. 32; TEC, Issues Paper submission, p. 22; Visy, Issues Paper submission, p. 2.

104 AER, Issues Paper submission, pp. 12-14; AGL, Issues Paper submission, pp. 12-14; International Power, Issues Paper submission, p. 8.

105 AGL, Issues Paper submission, p. 5; Alinta, Issues Paper submission, p. 21; International Power, Issues Paper submission, p. 25; LYMMCo, Issues Paper submission, p. 25

106 Infigen, Issues Paper submission, p. 4; Northern Group, Issues Paper submission, p. 21; Origin, Issues Paper submission, p. 2; TRUenergy, Issues Paper submission, p. 2.

107 AER, Issues Paper submission, p. 14; Alinta, Issues Paper submission, p. 21; EnergyAustralia, Issues Paper submission, p. 3; ENA, Issues Paper submission, p. 2; EUAA, Issues Paper submission, p. 17; Gallaugher, Issues Paper submission, p. 4; Grid Australia, Issues Paper submission, p. 22; Hydro Tasmania, Issues Paper submission, p. 6; International Power, Issues Paper submission, p. 24; LYMMCo, Issues Paper submission, p. 24; NGF, Issues Paper submission, p. 4; Northern Group, Issues Paper submission, p. 24; Origin, Issues Paper submission, p. 8, TEC, Issues Paper submission, p. 22; TRUenergy, Issues Paper submission, p. 6.

- costs imposed by generators under current frameworks;
- impacts of changes to access arrangements;
- design issues for generator charging; and
- transmission charging for load.

5.3.1 Costs imposed by generators under current frameworks

In the Final Report for the *Review of Energy Market Frameworks in light of Climate Change Policies* we recommended the introduction of a price signal in the form of a transmission charge on generation to reduce the costs associated with uninformed locational decisions by generators.[108] To enable the making of efficient decisions, such a signal should reflect the costs imposed by generators, and the extent to which these vary by location.

In that report, we noted a preference for a long term signal, such as that given by a transmission charge, as opposed to the short term signals that could be given through more granular energy pricing. A long term signal would provide a consistent, fixed signal for a significant period of time of perhaps a year, or even for the life of a power station. In contrast, short term signals provided by energy pricing would vary with every half-hour trading interval.

We considered that short term signals would be less effective in informing long run decisions for the following reasons:

- They are primarily targeted at improving efficiencies in short term dispatch and therefore have a lesser impact on locational decisions.
- They can change frequently and significantly as the pattern of network losses and congestion changes. They are therefore less predictable and credible in the long run.
- They introduce additional price risk for participants and often require accompanying risk management instruments. These can be difficult to design and create contentious issues around their allocation. This is discussed further in the next chapter.
- They may under-signal the total costs of network investment. This is primarily because there are large economies of scale when making network investments, resulting in lumps of network investment at a time. While this approach to transmission investment may be efficient, the presence of spare capacity reduces the scarcity value of the network and hence dampens the locational signal.

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108 For further details, see Chapter 3 and Appendix I of: AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, Sydney.

Given these considerations, we recommended the introduction of a long term signal, but noted that there were a number of potential approaches to estimating long run costs. This would be important in informing the level and structure of the charges.[109]

Stakeholder views

In submissions to the Issues Paper, stakeholders expressed a number of views regarding the costs imposed by generation.

In particular, the Northern Group contended that, under the non-firm access arrangements in the NEM, generators do not generally impose any costs on the transmission network. Network investment to enable a generator to be dispatched will only be undertaken if the augmentation passes the RIT-T (unless the generator chooses to fund the augmentation). It was suggested that the only way a generator could impose costs on the network would be by 'gaming' the RIT-T, but that this was highly unlikely.[110] The Commission understands that, under some circumstances, TNSPs might treat the fixed costs of generators that are planned but not yet constructed as being sunk. This might make a network augmentation seem net beneficial, although it may not have been if the fixed costs had been taken into account. This would imply that the resulting overall costs were higher than they needed to be.

Other stakeholders, when considering the costs imposed by generation, focussed on costs imposed in dispatch. They suggested that there were costs arising from new entrants constraining-off existing generators[111] or from preventing consumers receiving lower price generation through interconnectors.[112]

EnergyAustralia and the Energy Networks Association (ENA) noted that a locational price signal would allow generators to make efficient location decisions by trading off the costs they impose on the shared network with other factors, such as proximity to fuel.[113] The EUAA suggested that there would be cost differences attributable to time of use and voltage, as well as geography.[114]

Commission's current views

The Commission notes the views expressed by stakeholders. In particular, the Commission agrees that it is important that there is clarity as to the costs imposed by generators. The Commission intends to give further consideration to the way in which sunk generator costs may influence transmission investments justified on a market benefits basis under certain scenarios, as well as to whether generator locational

109 AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, Sydney, pp. 256-257.

110 Northern Group, Issues Paper submission, p. 21.

111 AGL, Issues Paper submission, p. 14; International Power, Issues Paper submission, p. 8.

112 AER, Issues Paper submission, p. 13.

113 EnergyAustralia, Issues Paper submission, p. 3; ENA, Issues Paper submission, p. 2;

114 EUAA, Issues Paper submission, p. 11.

decisions have any impact on the costs of transmission investments made on reliability grounds.

In terms of the costs resulting from increased congestion, the Commission notes that, under the non-firm regime, no compensation is paid to generators constrained-on or -off the system. There are therefore no costs that fall on transmission. Instead, these risks are borne by generators. However, as discussed in the previous chapter, there might be costs to consumers resulting from dispatch uncertainty and the potential consequential impacts on investment.

There may therefore be a case for a transmission charge based on the effects of a generator's locational decision on network congestion. However, substitute or complementary solutions might be provided through changes to the service provided to reduce constraint risks or through pricing intra-regional congestion. The Commission therefore intends to give this matter further consideration in conjunction with the Access and Congestion workstreams.

5.3.2 Impacts of changes to access arrangements

As indicated above, there needs to be an interaction between transmission charges and the service being provided. Load, unlike generation, faces locational signals through charges for the shared network. However, load also receives a different level of service as transmission reliability standards apply.

In the event that some level of firmer access service was provided to generators, such as through a transmission reliability standard for generation, a generator's locational decision would have direct cost implications. This is because network investment would be undertaken to maintain compliance with the standard, and this is likely to cost more in certain locations than others. Depending on the exact standard applied, it is likely that under these circumstances a cost signal would be important in ensuring that overall costs were minimised.

Equally, in the event that firm financial access rights were provided to generators with compensation payable in the event of constraints, potential additional costs would be imposed if a new entrant generator located in a congested part of the network. If this were to occur, the amount of compensation paid out for constraint risk in that part of the network would be likely to increase. There would therefore be a clear case for the levying of a charge to reflect these potentially increased costs.[115]

Relatively few stakeholders commented on these matters in submissions to the Issues Paper. However, LYMMCo observed that "charges should reflect the efficient cost of

115 However, a self-financing FTR regime (that was not, therefore, fully firm) would use settlement residues between nodes as the source of compensation. This would, in effect, internalise the costs of the locational decision (as new entrants without FTRs would fund congestion costs). In this case, an explicit transmission charge might be of lesser importance, being implicitly replaced by the amounts paid to obtain FTRs.

the network investment required to provide the defined level of service required by the new generator".[116]

A number of other stakeholders referred to deep connection charging, under which a direct cost signal of the investment required to maintain the physical access standard on the system would be provided by charging new entrant generators for these works. While some stakeholders considered that this would send clear locational signals,[117] others noted that this might discriminate against new entrants.[118]

Commission's current views

The Commission intends to give further consideration to the interaction between transmission charges and the service being provided to generators. In assessing any potential changes to transmission charging, it will first be necessary to have a clear and settled view on the service that should be delivered, and the costs of the providing this. This, in turn, will determine the necessity of providing signals of locational differences in these costs.

5.3.3 Design issues for generator charging

Although, as noted, it is important to be clear about the nature of the service being provided before considering the specifics of a charging regime, in submissions to the Issues Paper stakeholders raised a number of design issues for charging. Of these, the issue of deep connection charges has implications for the level of the service, which has already been discussed.

However, the wider question of whether any charges levied on generators should apply to all generators or just to new entrants was raised by a number of stakeholders. In some submissions it was suggested that charges should not be levied on incumbent generators as efficiency would not be enhanced by charging such generators after their locational decision has been made and that there would be no justification for recovering sunk costs from generators.[119] Another stakeholder suggested that charges should not be levied on incumbent renewable generation.[120]

However, other stakeholders suggested that charges should be levied on all generators, including incumbents, to ensure that there was a level playing field for competition and no barrier to entry.[121]

116 LYMMCo, Issues Paper submission, p. 26.

117 AER, Issues Paper submission, p. 13; Govt of SA, Issues Paper submission, p. 2; TRUenergy, Issues Paper submission, p. 6.

118 DPI, Issues Paper submission, p. 10.

119 Alinta, Issues Paper submission, p. 21; International Power, Issues Paper submission, p. 24; LYMMCo, Issues Paper submission, p. 26.

120 Hydro Tasmania, Issues Paper submission, p. 6.

121 EnergyAustralia, Issues Paper submission, p. 3; TEC, Issues Paper submission, p. 22.

A number of stakeholders expressed a view that any charges should be fixed at the time of connection, to minimise uncertainty and any consequent financing issues.[122] Northern Group noted that there might be a tension between forward-looking signals (which would vary to reflect cost changes) and long-term signals (which would be of most value if certain).[123]

Some concerns were expressed by stakeholders that there might be practical challenges with designing charges that provide a reliable and accurate signal of costs, in particular the need to forecast a range of factors such as future congestion, load growth and changing patterns of network flows.[124] It was also suggested that such a process might raise concerns about transparency.[125]

Finally, a number of stakeholders noted that cost reflectivity would be enhanced by charges being connection point specific, rather than calculated over a number of connection points.[126]

Commission's current views

The Commission notes the issues that stakeholders have raised, and agrees that there would be a large number of design issues that would require further consideration in developing any charging regime for generation. However, as previously highlighted, the overarching issue to be resolved is the nature of the service for which charges are being recovered. This also means that the issue of access is therefore a fundamental consideration in assessing the relative merits of deep connection charges.

5.3.4 Transmission charging for load

In the Issues Paper, we noted that, currently, all the costs of the provision of the shared network are recovered from load, and load does face locational cost signals under existing Transmission Use of System (TUoS) pricing methodologies. Pricing methodologies vary between TNSPs, although all TNSPs are required to calculate the locational charges imposed on load using either Cost Reflective Network Pricing (CRNP) or modified CRNP methodologies.

In response to concerns that these methodologies may over-signal usage costs, only a proportion of the costs that it is possible to allocate on a locational basis (50 per cent for CRNP) are included.[127] The remainder of the locational costs which are not recovered through CRNP, together with common services costs (which it is not possible to allocate on a locational basis), are recovered using postage stamp charging.

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122 AGL, Issues Paper submission, p. 24; International Power, Issues Paper submission, p. 25; LYMMCo, Issues Paper submission, p. 26.

123 Northern Group, Issues Paper submission, p. 24.

124 Grid Australia, Issues Paper submission, p. 22; Origin, Issues Paper submission, p. 8.

125 Northern Group, Issues Paper submission, p. 24.

126 AGL, Issues Paper submission, p. 24; International Power, Issues Paper submission, p. 25; LYMMCo, Issues Paper submission, p. 26.

127 NECA, *Transmission and Distribution Pricing Review, Final Report*, July 1999, p. 48.

As such, the locational charges levied on load give only an approximate signal of the long run marginal costs associated with further investment in the network. Further, many TNSPs continue to use the CRNP, as opposed to modified CRNP, methodology, which takes no account of the spare capacity on the system. This may result in perverse pricing signals. For example, if an element of the network is heavily utilised, CRNP will produce a lower unit price compared to a situation where there is spare capacity.

However, an implication of using modified CRNP is that the costs of the spare capacity are recovered using postage stamp charging. This can mean that less than 50 per cent of locational costs are recovered on a locational basis.

Currently, the costs of transmission in a region are recovered solely from load within that region. However, in the Final Report of the *Review of Energy Market Frameworks in light of Climate Change Policies* we concluded that these arrangements should be amended.[128] This is because they will result in implicit cross subsidies where there are positive net flows between regions. We therefore recommended the introduction of inter-regional transmission charges, such that importing regions would pay for the use of the transmission system in a manner consistent with other loads connected to the network in those exporting regions. As noted, the MCE has subsequently endorsed this recommendation and proposed a Rule change to this effect.

Stakeholder views

Relatively few submissions to the Issues Paper discussed transmission charges for load. AEMO suggested the introduction of a national transmission pricing regime, established in the Rules or administered by a single body, incorporating generation pricing. This approach would also ensure a nationally consistent approach to the charging of load.[129]

EnergyAustralia discussed a number of potential issues with current transmission pricing methodologies, including:[130]

- existing avoided TUoS arrangements are unstable and not cost reflective;
- there might be benefits from increased transparency in the explanation of changes to charges and the publication of material relating to pricing strategies; and
- there may be potential benefits from reforming transmission prices to follow economic principles rather than cost allocation principles.

Finally, the MEU proposed that the option of setting non-locational TUoS and Common Services charges using either demand or consumption should be changed to

128 AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, Sydney, Chapter 4.

129 AEMO, Issues Paper submission, p. 28.

130 EnergyAustralia, Issues Paper submission, pp. 3-4, 7-8.

only using demand. It was suggested that this would be more cost reflective and would provide better signals to reflect usage.[131]

Commission's current views

The Commission notes the views expressed by stakeholders in relation to transmission charging for load. The Commission also notes that if a locational price signal for generation is provided through transmission pricing methodologies, there might be consequential impacts for the charging of load. For instance, if a positive amount of revenue was recovered from generation, there would be a requirement for less to be recovered from load.

The Commission further notes the issues raised by stakeholders in response to the draft determination for the inter-regional transmission charging Rule change.[132] The draft determination proposed introducing inter-regional charging in a way which would be incremental and consistent with the existing TUoS methodologies. Such an approach would have the benefits of being simple, easier to implement and would minimise costs to TNSPs.

Stakeholders, in submissions to the draft determination, raised a number of concerns with the estimated inter-regional charges and the resulting reallocation of costs across regions. Large users argued against the high level of volatility in the charges, and other submissions questioned whether the resulting reallocation of costs would be consistent with the economic use of adjacent networks by regions. Submissions also noted the lack of consistency in TUoS methodologies across the NEM, and argued that this could undermine the effectiveness of inter-regional charging. These submissions have highlighted that there are a number of issues with existing TUoS methodologies that could impact on the efficiency of any inter-regional transmission charging scheme.

Way forward

On 7 April 2011, the Commission gave notice under section 107 of the NEL to extend the period of time for the making of the final Rule determination for inter-regional transmission charging to 23 February 2012.

The Commission has noted its agreement with the submissions received on its draft Rule determination that there is a need for consistency in the application of inter-regional transmission charging on a NEM-wide basis. It has therefore decided that an extension in the time period is warranted to develop a consistent national design for the inter-regional transmission charging mechanism and the methodology for calculating that mechanism. Further consultation with stakeholders on these issues will be undertaken through a Discussion Paper, which is intended to be published by July 2011.

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131 MEU, Issues Paper submission, p. 35.

132 AEMC 2010, Inter-regional Transmission Charging, Draft Rule Determination, 2 December 2010, Sydney.

However, the stakeholder comments have drawn attention to issues relating to the general framework governing how TUoS is calculated in the NEM and, in particular, to concerns about the lack of consistency between TNSP pricing methodologies. The Commission therefore considers that there is merit in more generally giving further consideration to these matters, which would also include:

- the split between locational and non-locational charges that is a key factor behind the annual volatility of inter-regional transmission charges under the current proposal; and

- the allocation of SRA proceeds, and the rationale for any changes in this area following the implementation of inter-regional charging.

The Commission notes that the current framework for transmission charging was established in 2006, and that there could be benefit in re-evaluating some of the principles of the framework given current circumstances and the application of TUoS charging over past years. However, given the Commission's ongoing assessment of the current Rule change request, the scope of any such work, and its relationship with this review, will need to be considered as part of the process of preparing the Discussion Paper.

6 Congestion

6.1 Introduction

This chapter covers the Congestion workstream identified by the Commission for further consideration. Understanding the materiality of congestion will be important in ensuring that any changes to the existing frameworks are proportionate to the scale of the problem.

The chapter outlines the issue and then discusses the aspects of it that the Commission intends to consider further in the review. A fuller discussion of the materiality of congestion, and approaches to quantifying this, is included as Appendix A.

6.2 What is the issue?

If insufficient transmission network capacity is provided to the market, either operationally or through insufficient or delayed network investment, there is a risk of inefficiently high levels of network congestion.

This congestion may constrain low cost generation off the system, to be replaced by higher cost plant, with the result that costs to retailers, and ultimately consumers, increase. In order to mitigate the risks associated with congestion, generators may engage in behaviour that leads to further inefficiencies in the market.

6.2.1 Mispricing and dispatch risk

When transmission networks are unconstrained, and electricity can flow freely between regions, settlement prices will be aligned across NEM regions. (There will be small price differences due to transmission losses.) When interconnectors between regions become congested, regional prices will diverge. If a constraint is present on an interconnector flowing into a region, more expensive generation in that region will need to be dispatched in place of cheaper imports. The settlement price in that region will therefore be higher.

In the short term, these higher prices provide a signal to generators in that region to produce more and to load in that region to consume less. In the longer term, the frequency and size of the price differences will encourage efficient decisions by market participants concerning when and where to invest in generation and load assets.

However, under the regional structure of the NEM, differences in the marginal cost of supply within a region are not reflected in settlement prices. Intra-regional congestion therefore leads to 'mispricing', in that the price used for settlement (the RRP) is different to the hypothetical shadow prices for each node that would reflect local demand and supply conditions.

It is mispricing that creates dispatch risk for generators. A generator can be constrained-off when it is not dispatched, or is dispatched for a lesser quantity than it is willing to produce for a given settlement price. Equally, there is a risk for generators of being constrained-on, in that the dispatch process may result in the generator being dispatched for a quantity that is greater than the amount it is willing to produce at the settlement price paid (assuming the generator takes no action to mitigate the risk).

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

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

6.2.2 Disorderly bidding

If congestion arises within a region, the discipline on generators to make offers that are reflective of their short run costs, that is a usual result of competition in the NEM, can break down. This is because generators located behind constraints know that their offers will not impact the price they receive, which is set by higher priced unconstrained generation elsewhere, and therefore have an incentive not to make cost-reflective offers. Constrained generators will instead offer capacity at a price which maximises their dispatch, which can often be at the market floor price of -$1,000/MWh. This has become known as 'disorderly' bidding, and results in network capacity behind constraints being rationed using non-cost-reflective prices.

The presence of disorderly bidding will mean that generators' offer prices do not reflect their underlying resource costs of production. This undermines the economic efficiency properties of the bid-based merit-order dispatch approach used in the NEM, and leads to less certain dispatch outcomes. Generators have less confidence about how every other generator may behave and therefore what the resulting dispatch outcomes will be.

If network capacity is rationed using non-cost-reflective prices, there will be a risk that efficient generators are not able to access the market as they have no mechanism to signal the value they place on this access. As discussed in Chapter 4, reduced certainty of dispatch outcomes will impact financial markets, increasing costs and potentially discouraging investment in new generation plant.

Disorderly bidding may also impact the certainty of inter-regional trade. This is because generators bidding at low (or negative) prices to avoid being constrained-off (and which can afford to bid low because their offer will not affect the regional price) in the presence of an intra-regional constraint will be dispatched ahead of generators in other regions (which will be settled at different regional prices, and which therefore cannot afford to bid in the same manner). This can drive counter-price flows from regions with high settlement prices (due to the intra-regional constraint) to regions with lower settlement prices. As the IRSR units auctioned are unidirectional, they will not provide an effective instrument to manage to the divergence in regional prices in the presence of counter-price (or zero) flows. This therefore increases the risks associated with trading between regions.

6.2.3 Previous recommendations made by the Commission

As noted in chapter 1, in the Final Report for the *Review of Energy Market Frameworks in light of Climate Change Policies*, we set out our recommendation that, where practical and proportionate, the prices generators receive in the wholesale market should reflect network congestion, in particular where there are pockets of material and transitory congestion.[133] This would remove the incentives for disorderly bidding, and lead to more efficient and certain dispatch outcomes. The current review provides the opportunity to assess the practicality and proportionality of such a measure, which is discussed in section 6.3.4.

In the Final Report for the *Review of Energy Market Frameworks in light of Climate Change Policies*, we also recommended that, in principle, generators should be able to negotiate and pay for an enhanced level of transmission service - but that this needed further analysis for practical application.[134] This, and other changes to the nature of access, might address issues associated with dispatch risk and inefficiency in the dispatch of generation. However, such changes would fundamentally alter the service provided by transmission, and have already been discussed in chapter 4. The potential measures discussed later in this chapter would also seek to address such issues, but would aim to do so in way that does not materially alter the role of transmission.

6.3 Areas for further consideration

In light of submissions to the Issues Paper, the Commission has identified four key areas for further consideration in the review. These are:

- the materiality of congestion;
- network availability;
- generator behaviour; and
- congestion management mechanisms.

The following sections consider each of these areas in turn.

133 AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, Sydney, p. 26.

134 Ibid.

6.3.1 Materiality of congestion

A key focus of the review is to assess the extent to which the existing market arrangements are able to manage congestion both currently and in the future. We highlighted a concern in the *Review of Energy Market Frameworks in light of Climate Change Policies* that climate change policies such as the expanded RET and the potential introduction of a carbon price will 'stress-test' the capability of the existing frameworks to manage congestion going forward.[135] However, the extent to which such impacts are assessed to be material will have an important bearing on the form and scope of framework changes that may need to be made.

Stakeholder views

Perspectives on whether congestion is, or is likely to be, material have typically differed between stakeholders, as reflected in submissions to a number of prior reviews, such as the *Congestion Management Review* and the *Review of Energy Market Frameworks in light of Climate Change Policies*. Submissions to the Issues Paper for this review were no different.

The Northern Group suggested that congestion might be unlikely to increase and contended that mispricing/disorderly bidding has not been a material issue to date.[136] It highlighted AER data on the Total Cost of Constraints, indicating that congestion costs in 2008/09 had materially decreased from the previous year, and that these costs were, in any event, relatively modest given the scale of the market.[137]

The Northern Group also noted that a significant portion of congestion costs arise as a result of transmission outages, which would be difficult to avoid by changes to market frameworks.[138] It further suggested that current or anticipated levels of congestion did not seem to be affecting incentives to invest in generation capacity, given investment patterns to date and AEMO Electricity Statement of Opportunities (ESOO) data on committed and planned investment in the NEM.[139]

Other stakeholders disagreed with this view. LYMMCo, for example, contended that congestion would have serious impacts on individual generators.[140] AGL and International Power presented similar views and outlined some examples when individual generators or groups of generators had been affected by congestion, primarily arising from what they perceived as inefficient locational decisions.[141]

TRUenergy indicated that on one occasion in particular (on 29 January 2009) it had faced the prospect of being constrained-off the system for a period of 7 hours at the

135 Ibid, p. 29.

136 Northern Group, Issues Paper submission, pp. 33-39.

137 Ibid, p. 34.

138 Ibid.

139 Ibid, p. 7.

140 LYMMCo, Issues Paper submission, p. 12.

141 AGL, Issues Paper submission, pp. 10-12; International Power, Issues Paper submission, p. 14.

market price cap.[142] This event was driven by simultaneous high demand in Victoria and a failure of one of the four Hazlewood 500kV transformers. This would have impacted on TRUenergy's ability to deliver contracted energy from the Jeeralang and Yallourn Power Stations. It commented that:

> "We estimated that this low probability/high impact event would cost TRUenergy in excess of $55m and potentially more than that to each of the other three major Latrobe Valley generators. The congestion of the day was not as serious as had been forecast in the Australian Energy Market Operators (AEMO's) pre-dispatch as a result of quick response by SP AusNet. Nevertheless, had this single event eventuated it could have materially threatened the financial viability of all of the Latrobe Valley generators."

While market participants tended to point to individual impacts of congestion, AEMO attempted to quantify the consequences on the market more broadly. AEMO focussed on a constraint triggered on 7 December 2009 on a transmission line between Wallerawang and Mount Piper, due to a planned outage.[143] The constraint has bound on a number of occasions and, on each occasion, it has led to high prices being set in New South Wales by Delta Electricity units at Wallerawang and substantial generation capacity being constrained-off in New South Wales. Interconnectors between Victoria and New South Wales, and between Queensland and New South Wales, were also constrained down to zero.

As a consequence, during the period from 11:30AM to 5:00PM on 7 December 2009, the New South Wales price averaged $5,071/MWh, whilst Queensland and Victoria averaged $172/MWh and $22/MWh respectively. An important further outcome was that, because the interconnectors were reduced to low flow levels, the hedging instrument provided by the SRAs provided a zero payout at a time when the price differences between the regions was very high.[144]

AEMO performed a 'what-if' analysis of the day's events. This was carried out by re-running the dispatch engine for the same market and power system conditions, but using a bidding pattern based on the last bids that were submitted by generators that morning before they became aware of the constraint. The outcome of this analysis was that New South Wales prices would have averaged around $90/MWh against the actual outcome of $4,917/MWh. AEMO calculated that this would have reduced pool settlement by about $300m.[145]

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142 TRUenergy, Issues Paper submission, p. 19.

143 AEMO, Issues Paper submission, Appendix B.

144 Ibid, p. 11.

145 Ibid.

Submissions from a number of other stakeholders also pointed to this constraint in particular as demonstrating some of the broader implications of congestion in the NEM.[146]

However, the Northern Group identified the total cost of this constraint for the 70 hours which it bound during 2009-10 as being in the order of $6.4m. The Northern Group also suggested that the constraint was transitory in nature and could not credibly be described as being a "system normal" constraint.[147]

Commission's current views

It is evident from submissions that stakeholders have significantly differing perspectives on the materiality of congestion. Some stakeholders acknowledged this, with one commenting that:[148]

> "...after 12 years the market seems unable to agree a real measure of transmission congestion."

The Commission therefore considers that a critical part of the review will be to assess, and form a view, on this issue. To form a basis for this work, we have developed an economic assessment framework for establishing the materiality of congestion, which is set out in Appendix A.

However, it is clear from our work to date that all the studies previously undertaken to examine congestion in the NEM have suffered from some limitations in their application and, consequently, in the conclusions that can be drawn. For example, the figures quoted by AEMO in relation to the events of 7 December 2009 do not account for the effects of the contract market, which mean that the impact on consumers would likely have been considerably less than the $300m change in pool settlement quoted.

In Appendix A we therefore discuss some of the limitations of previous studies and canvass stakeholder views on ways in which the analysis of the costs of congestion could be further developed.

6.3.2 Network availability

In the Issues Paper we set out the importance of TNSPs operating their networks to ensure that capability can be maximised. This is likely to become critical as patterns of generation change and new generation enters the market, increasing the risk of congestion. While congestion will eventually be built out where it is efficient to do so, in the interim appropriate incentives should be present such that the network is managed so as to minimise the costs of congestion.

146 AER, Issues Paper submission, pp. 2-5; DPI, Issues Paper submission, p. 11; EUAA, Issues Paper submission, p. 14.

147 Northern Group, Issues Paper submission, p. 33.

148 Alinta, Issues Paper submission, p. 23.

These incentives are currently provided by the Service Target Performance Incentive Scheme (STPIS), which is 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.

The scheme is comprised of two components:[149]

- a Service Component which provides incentives for TNSPs to minimise the number and duration of loss of supply events, and to maximise circuit availability; and

- a Market Impact Component which provides incentives for TNSPs to minimise the market impact of transmission outages, based on the number of dispatch intervals where an outage on a TNSP's network results in a network outage constraint with a marginal cost that exceeds $10/MWh.

Currently, for the Service Component TNSPs face a financial incentive in the range of plus or minus 1 per cent of regulated revenue, and between zero and plus 2 per cent for the Market Impact Component.

In the Issues Paper we asked whether reforms were required to these incentives on TNSPs to manage networks efficiently and to maximise operational network capability for the benefit of the market.

Stakeholder views

In submissions to the Issues Paper, a number of stakeholders declared their support for enhanced incentives to maximise network capability.[150]

A variety of approaches to further developing such incentives, and their effectiveness, were identified. The NGF submitted that TNSPs could at some level be exposed to the cost of congestion as a result of their investment decisions, and that this could be achieved either by:

- considering the potential for exposing TNSPs to the market costs of congestion; or

- increasing the TNSPs' revenue at risk under the current STPIS to ten per cent of regulated revenue or similar.[151]

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149 Australian Energy Regulator, *Electricity transmission network service providers - Service target performance incentive scheme (incorporating incentives based on the market impact of transmission congestion)*, *Final decision*, March 2008.

150 AEMO, Issues Paper submission, p. 29; AER, Issues Paper submission, p. 5; AGL, Issues Paper submission, p. 29; International Power, Issues Paper submission, pp. 31-32; LYMMCo, Issues Paper submission, p. 30; NGF, Issues Paper submission, p. 12; Origin, Issues Paper submission, p. 3; TRUenergy, Issues Paper submission, p. 5.

151 NGF, Issues Paper submission, p. 9.

However, International Power considered that making TNSPs directly responsible for congestion costs would be problematic, because:

- it would impose levels of risk on TNSPs that would be inconsistent with the existing low risk business model;
- TNSPs would need to develop expertise in the wholesale market to understand and manage these risks; and
- TNSPs would need to trade and hedge in the wholesale market and this might lead to conflicts with other TNSP roles.[152]

International Power therefore considered that the existing approach of placing tariffed penalties on TNSP operations that impose costs on the market should be strengthened and deepened by the AER through a process of continuing, incremental reform.[153]

LYMMCo considered that incentive regimes have a net positive benefit on the culture of TNSPs, and therefore suggested that there might be benefits from the use of sharper incentives. In particular, exposing TNSPs to some level of exposure to congestion costs to the market, when controllable by TNSPs, and reviewing the appropriate amounts of revenue at risk were proposed as being worthy of further consideration.[154]

Some submitters also discussed the types of behaviour that incentives should aim to encourage, such as the temporary increase of line ratings and rescheduling outages.[155] In particular, the AER commented that TNSPs' ability to respond to an incentive mechanism to reduce the market impact of network events had been illustrated by TransGrid's action, from late February 2010, to increase the ratings of the Mount Piper to Wallerawang lines.[156]

In its submission, Grid Australia outlined its agreement with the view that small initiatives by TNSPs can, at times, have a significant impact on transfer capability and congestion, although it suggested that whether opportunities for such initiatives exist will depend upon the circumstances of the particular network. Grid Australia noted that there are already measures in place that influence these initiatives, but also that it would welcome further analysis of whether a financial incentive that is more directly focussed on initiatives that influence transfer capability may advance the NEO.[157]

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152 International Power, Issues Paper submission, p. 31.

153 Ibid, pp. 31-32.

154 LYMMCo, Issues Paper submission, p. 30.

155 AEMO, Issues Paper submission, p. 14; AGL, Issues Paper submission, p. 29; International Power, Issues Paper submission, p. 31.

156 AER, Issues Paper submission, p. 7.

157 Grid Australia, Issues Paper submission, p. 23.

Commission's current views

The Commission agrees with the views expressed by a number of stakeholders that the use of financial incentives is likely to be important in encouraging TNSPs to take steps to maximise network availability and minimise the market impacts of congestion.

The Commission notes the intention of the AER to commence a review of the STPIS in the second quarter of 2011.[158] The Commission's further considerations of this matter will therefore be cognisant of this work, and any potential policy packages developed for further assessment will be informed by this.

6.3.3 Generator behaviour

In submissions to the Issues Paper, some stakeholders highlighted that generators may engage in forms of behaviour other than revising offers in response to mispricing.

In particular, AEMO highlighted that generators may also respond to the risk of being constrained-on by reducing availability below their true capability. Where system insecurity would otherwise occur, a compensated AEMO direction[159] usually results.[160]

Equally, in response to the risk of being constrained-off, generators may reduce their maximum Rate of Change (ROC). The ROC limits the amount a unit may be moved from one dispatch interval to the next, and setting the ROC at the limit of 3MW/min would generally act to slow the impact of being constrained-off.[161]

The AER highlighted the use of these types of behaviour, as well as the revision of offers, in connection to the constraint between Wallerawang and Mount Piper discussed earlier. The AER suggested that, on occasions when the constraint bound, Delta Electricity typically:

- "reduced the rate at which the Mount Piper power station could be ramped down when it was constrained off. The reduced ramp rate meant that the power station responded more slowly than anticipated to being constrained off."
- "withdrew capacity from Wallerawang during the acute supply period. At the time Wallerawang was meant to be increasing supply in response to the constraint."

158 AER, Issues Paper submission, p. 10.

159 Under Rule 4.8, AEMO is permitted to direct a market participant to modify its behaviour if there is a perceived security or reliability risk to the power system. There are also provisions in the Rules for market participants to be compensated if they incur additional costs as a result of being directed by AEMO.

160 AEMO, Issues Paper submission, p. 22.

161 Ibid.

- "altered its offers to generate by shifting substantial quantities into extreme price bands (this occurred on three of five days). Other generators also rebid capacity into higher price bands."[162]

The AER expressed concerns that the market impacts of disorderly bidding by generators "are neither efficient nor predictable and could pose a threat to the stability and safety of the power system".[163]

Commission's current views

The Commission notes the views expressed by stakeholders, and that the generator behaviours discussed above represent a rational response to the incentives created by the current market design.

However, the Commission is concerned both by the economic effects of this behaviour and by any threat that might be posed to the security of the system. The Commission therefore intends to give further consideration to these matters under this review, in combination with an assessment of whether changes could be made to the market design which would remove the incentives for such behaviours.

6.3.4 Congestion management mechanisms

Achieving efficient dispatch outcomes requires generators to offer their capacity to the market at cost-reflective prices. Given that the discipline to do this breaks down when there is a disconnect between a generator's offer price and the price it receives in settlement, a potential solution is to alter the prices a generator receives in the presence of congestion. This can be done by exposing a generator to its 'local' or 'nodal' price, which is reflective of the marginal cost of supply at the relevant node.

Pricing congestion in this manner would contribute to more efficient dispatch outcomes, as demand is more likely to be met using the least-cost mix of generation. If generators know that they all have the discipline to use cost-reflective offers, there would also be a greater degree of certainty around dispatch outcomes. This could lower trading risks. The overall market outcomes are likely to be lower, more competitive wholesale and contract prices.

It was these factors that led to our recommendation in the Final Report for the *Review of Energy Market Frameworks in light of Climate Change Policies* that a form of congestion pricing should be introduced.[164] However, we indicated that, in considering the introduction of a mechanism to implement this recommendation, a number of key questions would need to be addressed, including:

162 AER, Issue Paper submission, p. 3.

163 Ibid, p. 6.

164 AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, Sydney, p. 26.

- the coverage of the congestion pricing within the wholesale market - whether it should apply to a selected group of generators or to all generators in the market;
- whether it should be a permanent or temporary feature of the market; and
- whether its implementation would be practical and proportionate, such that the benefits outweighed the costs.

Management of basis risk

In making our recommendation, we noted that the introduction of a congestion pricing mechanism would introduce a different risk into the market, in that generators contracting with participants at other nodes would be exposed to a risk of differences in nodal prices ('basis risk'). As discussed in Box 4.1, generators are currently protected against this risk within regions in that they receive the RRP, and this can be thought of as including a risk management element equal to the difference in the shadow nodal price and the RRP.

Congestion pricing mechanisms that expose generators to nodal prices could include instruments to manage basis risk constructed from the intra-regional settlement residues that would result. The FTRs discussed in section 4.3.5 would be one example of this. In the Final Report for the *Review of Energy Market Frameworks in light of Climate Change Policies*, we set out a number of options for the allocation of these residues or rights. In particular, one option would be to automatically allocate these based on presented plant availability, rather than based on dispatch, as is effectively the case at present. However, we noted that this was a complex and problematic issue.[165]

In the *Review of Energy Market Frameworks in light of Climate Change Policies*, we also canvassed stakeholders as to whether there would be merit in investigating possible options to use external funds to improve the firmness of IRSRs,[166] and therefore their effectiveness as a means of managing the risk associated with inter-regional trading. However, we noted that using external funds would increase costs and, depending on where the external funding is sourced, the costs may be difficult for participants to manage. There was no stakeholder support for such reforms.[167]

Stakeholder views

In submissions to the Issues Paper, a number of stakeholders expressed support for a congestion pricing mechanism, or at least for examining such a proposal.[168]

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165 Ibid, Appendix J.

166 As indicated in Box 4.1, IRSR units represent a percentage of the settlement residues, not a 'firm' MW allocation. If an interconnector is constrained below its capacity, then each IRSR unit will not provide a full hedge.

167 AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, Sydney, p. 41.

168 AEMO, Issues Paper submission, pp. 29-30; AER, Issues Paper submission, p. 6; AGL, Issues Paper submission, p. 30; Alinta, Issues Paper submission, p. 26; Gallaugher, Issues Paper submission, p. 4;

However, stakeholders recognised the complex design issues involved, and the potential significant costs and side effects that would result. In particular, support was expressed for further examining the option of allocating residues by generator availability.[169]

Stakeholders commenting on the issue also generally favoured permanent models that covered the whole market, as opposed to temporary, localised schemes.[170] For example, International Power made the following points:

- "...under a complete regime, congestion prices (of some sort) would be established automatically whenever and wherever congestion arose."
- A partial regime would be "liable to 'miss' some of the congestion, since a partial regime will necessarily require predictive triggers to decide when and where the regime should apply, and forecasting of congestion is notoriously difficult and unreliable."
- "... the only possible advantage of a partial regime would lie in its cheaper or easier implementation", but "...to run parallel pricing and settlement systems - one with congestion pricing in place and one without - must necessarily be more complex than running a single regime."
- "Any partial regime would also impose uncertainty on participants in relation to when and where it would operate, and thus would inhibit hedging beyond the time horizon of the regime."[171]

A number of stakeholders also proposed some guiding principles for any congestion pricing mechanism, including that settlement should be financially balanced (i.e. the scheme should not draw upon or add to existing settlement flows) and that access to the regional market should, to the extent practical and reasonable, be preserved (i.e. as far as possible, intra-regional hedging should be allowed without basis risk).[172]

However, other stakeholders were opposed to the introduction of congestion pricing.[173] These stakeholders generally considered that the introduction of such a scheme would add complexity and risk to the market, particularly in contracting, and this would be likely to far outweigh the benefits in terms of reduced mispricing.

Govt of SA, Issues Paper submission, p. 1; International Power, Issues Paper submission, p. 33; LYMMCo, Issues Paper submission, p. 31.

169 AEMO, Issues Paper submission, pp. 29-30; AER, Issues Paper submission, p. 6; AGL, Issues Paper submission, p. 30.

170 AGL, Issues Paper submission, p. 30; International Power, Issues Paper submission, p. 34; LYMMCo, Issues Paper submission, p. 32.

171 International Power, Issues Paper submission, p. 34.

172 AGL, Issue Paper submission, p. 30; Alinta, Issues Paper submission, p. 26; International Power, Issues Paper submission, p. 35.

173 Infigen, Issues Paper submission, p. 9; Northern Group, Issues Paper submission, p. 29; Origin, Issues Paper submission, p. 9; Snowy Hydro, Issues Paper submissions, p. 1; TRUenergy, Issues Paper submission, p. 9.

Many of these stakeholders opposed to congestion pricing highlighted the other mechanisms in the market that they considered should resolve congestion issues, such as investment under the RIT-T and changes to regional boundaries.[174]

Finally, AEMO provided information suggesting that the effectiveness of IRSR units as an instrument to manage inter-regional trading risks has been poor and, in some cases, may have been declining in recent years.[175]

Commission's current views

The Commission notes the views expressed by stakeholders, especially in relation to issues associated with the implementation of a congestion pricing mechanism that can be applied on a localised, time-limited basis.

The Commission also continues to believe that the principal drawback in introducing localised pricing for generation would be the implications for contracting, and that the issue of allocating residues or rights to manage basis risk would be likely to be particularly challenging.

Nevertheless, the Commission intends to give further consideration to the costs and benefits of congestion pricing, and agrees with stakeholders that a range of models, including one which allocates residues according to plant availability, should be assessed. Clearly, there is a significant interaction with the Access workstream, and the development of any models for assessment will need to be undertaken on an integrated basis.

The Commission also intends to assess the risks that already exist with regards to inter-regional trading. To this end, the Commission would welcome information and views from stakeholders as to the extent of trading between regions and the effectiveness of the IRSR units as instruments to manage the risks associated with this.

174 Origin, Issues Paper submission, p. 9; TRUenergy, Issues Paper submission, p. 9.

175 AEMO, Issues Paper submission, Appendix A.

7 Planning

7.1 Introduction

This chapter covers the Planning workstream identified by the Commission for further consideration. There is a strong linkage between the planning of the system and the service that is being provided by transmission.

The chapter outlines the issue and then discusses the aspects of it that the Commission intends to consider further in the review.

7.2 What is the issue?

The nature and timing of transmission investment is driven by the need to meet prescribed reliability standards at least cost, and to deliver net market benefits. The planning and investment frameworks support the safe, secure and reliable delivery of power to loads and define the 'default' level of transmission service that is provided.

A slow response to efficiently building out congestion can exacerbate the economic costs associated with congestion by restricting the ability of generators (both existing and new) to access the wholesale market. While building out all constraints would be inefficient, persistent congestion may indicate that insufficient network investment is being undertaken to support the wholesale market.

The challenge for the planning and investment frameworks will therefore be to ensure efficient and timely investment in transmission, especially in light of the anticipated different and uncertain patterns of flows across the network in future.

7.2.1 Transmission planning frameworks

Under Chapter 5 of the Rules and various jurisdictional instruments, TNSPs are required to plan and develop their transmission networks in a specified geographical area to meet power quality and reliability standards. TNSPs are also able to undertake investment where augmentations to the network would result in a net market benefit (but not necessarily to meet a specific reliability requirement).

The existing reliability standards for load vary between jurisdictions and, in some cases, lack transparency. To provide greater consistency across the NEM, the Commission has recommended a national framework for transmission reliability standards. However, as noted earlier, this framework has not yet been implemented.

As a consequence, there is little consistency between jurisdictions. Most notably, under the probabilistic planning approach employed in Victoria network augmentations in that jurisdiction are justified on a cost-benefit basis. This may lead to a lack of transparency and predictability. Inconsistency in standards may also result in differing levels of network capacity being provided in different regions.

Providing a national focus for planning

TNSPs are required to produce Annual Planning Reports (APRs), containing details of potential network augmentations given forecast loads. However, obligations to meet transmission reliability standards do not extend across state boundaries. Therefore, incentives to drive inter-regional investment are weaker than those for intra-regional investment because it has to be justified solely on a market benefits basis. There is also a less clear allocation of responsibility, in that (at least) two TNSPs will need to be involved in planning any inter-regional investment.

To address these issues, a number of recent reforms have been implemented to facilitate a more national approach to planning. The most significant of these is the NTP.

The NTP, which commenced as part of AEMO on 1 July 2009, has responsibility for identifying investments that may achieve the efficient development of the grid through publication of the annual NTNDP. The NTP therefore considers planning in respect of National Transmission Flow Paths (NTFPs), including possible upgrades to facilitate inter-regional flows.

Such flows are likely to become more important as patterns of investment change and renewable generation clusters in regions that are rich in renewable resources. The ability to access other regions will contribute to reduced congestion and will be essential to promote efficient inter-regional dispatch. The different planning arrangements for interconnectors will therefore need to provide timely and efficient investment in inter-regional network capacity.

Planning information

The APRs published by TNSPs document the annual planning reviews undertaken. These reviews aim to identify emerging constraints given forecast loads. The load forecasts are therefore key in driving the need for any network augmentation or non-network solution required to address a constraint. The load forecasts are provided to AEMO for use in the ESOO, which also contains information on new generation entry.

In undertaking an annual planning review, a TNSP is required to take into account the most recent NTNDP, and how augmentations relate to the development strategies for NTFPs that are specified in the NTNDP. This provides a national perspective on uncertain long term changing patterns of generation and load (including demand side response), and their associated network impacts.

In the Issues Paper, we therefore asked whether current transmission planning frameworks provide adequate information to TNSPs on where and when to invest, or when to defer or avoid investment. We also asked if additional market-based signals could be incorporated into the planning frameworks, and whether this would be beneficial. Market mechanisms could be used to build on or supplement the existing arrangements. We questioned whether market based signals could be introduced that would give more certainty to planners, and therefore improved investment signals and a reduced risk of network assets being under-utilised.

7.2.2 Promoting efficient transmission investment

The economic framework for the identification of efficient transmission investment projects has, from 1 August 2010, been provided by the newly implemented RIT-T. The new test amalgamates the separate reliability and market benefits limbs of the regulatory test that was previously used, thereby supporting an integrated assessment of costs and benefits for investment proposals. It also provides a greater national focus on market benefits associated with any transmission investment.

This measure should help to ensure that any new investment in the network maximises benefits to the NEM while at the same time meeting reliability standards. The requirement for broader and deeper calculation of market benefits under the RIT-T is intended to encourage TNSPs to assess and undertake the considerable transmission investment likely to be necessary for connecting significant volumes of new generation capacity and responding to changes in network flows.

However, there may be some challenges in applying the RIT-T to proposed network augmentations that are not required to meet a specific reliability requirement to pass the test. Under the RIT-T, augmentations that are predominantly meeting a reliability standard can proceed on a least cost basis. However, a proposed augmentation that is primarily to improve the efficiency of spot market outcomes must yield a net benefit to the market. It may be difficult for some types of market benefits, particularly competition benefits, to be demonstrated.[176]

Further, the RIT-T will not ensure that TNSPs will undertake all projects that it would be efficient to do so. This is because, unlike meeting reliability requirements, there is no legal obligation under the Rules or direct financial penalty imposed on TNSPs for not progressing a proposed project that is primarily to address congestion or any other market benefit.[177] The emphasis has traditionally been on reliability projects, and it is also more difficult to identify a failure to undertake investment that provides net market benefits.

To address this issue, the Last Resort Planning Power (LRPP) is vested in the AEMC to ensure timely and efficient inter-regional transmission investment for the long term interests of consumers of electricity. The LRPP allows the AEMC to direct registered participants to apply the RIT-T to potential transmission projects where the AEMC considers that the project is likely, if constructed, to relieve forecast constraints in respect of national transmission flow paths between regional reference nodes.

176 Modelling some types of market benefits, particularly competition benefits, can be difficult. The market scenarios used to evaluate proposed and alternative projects are very complex, and there are substantial uncertainties underlying the scenarios.

177 TNSPs may incur an opportunity cost by not undertaking network augmentations. Projects that are intended to drive more efficient outcomes in the wholesale market are rolled into the regulatory asset base and receive the same weighted average cost of capital as projects to meet reliability standards. Therefore, by not undertaking such investment TNSPs are foregoing potential revenues and returns.

The LRPP is intended to be utilised only in those circumstances where there is a clear indication that the existing planning mechanisms are unlikely to deliver efficient inter-regional transmission investment. Before the AEMC can exercise the LRPP, it must clearly identify that such an investment shortfall problem exists, be satisfied that this problem is likely to have a material market impact, and that it will not be addressed unless the LRPP is exercised.

The LRPP and the NTP are therefore intended to provide transparency and to encourage TNSPs to identify areas of the network which may need reinforcement or augmentation and test potential new transmission projects. However, these elements of the framework, together with the RIT-T itself, are still relatively new and untested.

7.3 Areas for further consideration

In light of submissions to the Issues Paper, the Commission has identified five key areas for further consideration in the review. These are:

- Transmission Reliability Standards for load;
- the RIT-T;
- national planning and inter-regional augmentation;
- planning information and proactive planning; and
- institutional arrangements.

The following sections consider each of these areas in turn.

7.3.1 Transmission Reliability Standards for load

As noted in chapter 4, a number of stakeholders suggested in their submissions to the Issues Paper that transmission reliability standards for load would have a direct effect on levels of congestion, and therefore dispatch uncertainty for generators.

In particular, it was suggested that the probabilistic planning approach employed in Victoria, which permits investment only on economic grounds and does not provide for a deterministic level of redundancy, results in a lesser level of transmission capacity than is the case in other states.[178] Generators from Victoria and from other states both saw this issue being of major importance, with the Northern Group venturing that "differences in deterministic versus probabilistic transmission planning standards between regions may be the key underlying reason for the different industry views on the need for change to the current transmission framework".[179]

One stakeholder with significant interests in Victoria - TRUenergy - submitted that:

178 Alinta, Issues Paper submission, p. 14; TRUenergy, Issues Paper submission, p. 3.

179 Northen Group, Issues Paper submission, p. 16.

> "Probabilistic planning did not deliver the level of intra-regional transmission investment required in Victoria in the past 10 years. Of particular concern, is the probabilistic planning regime's ability to deliver the required level of transmission investment required by Victoria in the next 10 years, especially given the level of renewable generation forecast."

TRUenergy further suggested that the resulting congestion will have the effect of generators reducing "their contracted capacity in order to reduce their chances of being 'constrained off' thereby reducing the liquidity of the contract market", and that the use of deterministic planning on an N–1 basis in Victoria would result in more timely transmission augmentations than at present.[180]

However, some stakeholders did support the use of probabilistic planning. Indeed, one commented that a more sophisticated probabilistic planning methodology than that used in Victoria should be adopted across the NEM,[181] while AEMO discussed the potential use of an economic cost-benefit planning approach on a national basis.[182]

It was also suggested that implementation of the recommendations of the Commission's Transmission Reliability Standards Review "may allay concerns about varying regional reliability standards and corresponding investment trends".[183]

Commission's current views

As discussed, the Commission has already provided recommendations to the MCE on this matter. However, it should be noted that the national framework proposed by the Commission provides for the introduction of transmission reliability standards that are economically derived. While these would generally be fixed for a given period and expressed in a deterministic manner, there would also be the option of allowing the making of transmission investment decisions using probabilistic cost-benefit analysis.[184]

The probabilistic planning approach currently used in Victoria would therefore be consistent with the proposed national framework, subject to certain requirements relating to reporting to increase transparency and to allow for comparisons to be made across jurisdictions. To the extent that concerns around probabilistic planning are justified, they would not therefore be addressed by the implementation of the recommendations of the Commission's Transmission Reliability Standards Review.

However, the Commission notes that the relevant issue is the outcomes of the planning process in question, rather than the nature of the process itself. The Commission also notes that the intention of the current transmission reliability standards is to provide

180 TRUenergy, Issues Paper submission, pp. 2-4.

181 Gallaugher, Issues Paper submission, p. 2.

182 AEMO, Issues Paper submission, p. 27.

183 Northern Group, Issues Paper submission, p. 16.

184 AEMC 2010, *Transmission Reliability Standards Review*, Updated Final Report, 3 November 2010, p. 16.

reliable supply to load; any effect, or varying effects, on generation is effectively a by-product of the process. Therefore, in assessing the level of network capacity available to generators, it may be more appropriate to directly consider a transmission reliability standard for generation that is designed with this end in mind. (This is discussed in chapter 4.)

Nevertheless, in giving consideration to a transmission reliability standard for generation, it would be necessary to examine the interactions with transmission reliability standards for load, both those currently applying and those that would result from the adoption of the Commission's proposals made in the Transmission Reliability Standards Review.

7.3.2 The RIT-T

In the Issues Paper we asked whether existing frameworks, including the RIT-T, would provide for efficient and timely investment in the shared transmission network. A description of the RIT-T is provided in Box 7.1.

In response to the Issues Paper, a number of stakeholders, noting that the RIT-T had only commenced operation on 1 August 2010, contended that there had been insufficient time to determine the effectiveness of the RIT-T.[185]

185 EnergyAustralia, Issues Paper submission, p. 6; ENA, Issues Paper submission, p. 6; Grid Australia, Issues Paper submission, p. 7.

Box 7.1 The Regulatory Investment Test for Transmission

The RIT-T, which replaced the former regulatory test from 1 August 2010 for transmission, establishes the processes and criteria to be applied by a TNSP in considering investment in its transmission network. The purpose of the RIT-T is:[186]

> "to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market."

Where investment is being undertaken to meet reliability standards, the preferred option may have a negative net economic benefit in which case the RIT-T should identify the option which minimises these costs.

The RIT-T combined the two limbs of the former regulatory test and introduced a new process to facilitate stakeholder consultation in identifying the most efficient option to meet an identified need. Augmentations and other new transmission investment typically must be assessed under the RIT-T.[187]

The RIT-T, as set out in the Rules, comprises two elements:

- a process element, which includes the procedural consultation requirements[188] and a dispute resolution mechanism.[189] Under the time frames mandated in the Rules, the RIT-T process takes at least seventeen months from the issuance of the project specification report, and potentially over two years if the TNSP's conclusions are disputed; and
- the test itself, which examines the costs and benefits of each credible option to establish the option that maximises net market benefits (or minimises costs where the investment is required to meet reliability standards).

In applying the RIT-T, TNSPs are required to consider a range of credible options to meet an identified need and may then proceed with the one that provides the greatest net market benefits (or minimises costs where the investment is required to meet reliability standards). This implies that TNSPs must consider a range of scenarios that meet the identified need of the transmission investment.

However, a significant number of stakeholders raised a number of potential issues with the RIT-T, including general concerns that it is unlikely to provide for efficient and timely investment in the shared network to build-out intra-regional congestion.[190]

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186 NER clause 5.6.5B(b).

187 There are several exceptions to this requirement, which are set out under clause 5.6.5C of the Rules.

188 NER clause 5.6.6.

189 NER clauses 5.6.6A and 5.6.6AA.

190 Brookfield, Issues Paper submission, p. 5; CEC, Issues Paper submission, p. 6.

More specifically, the following perceived issues were highlighted:

- There might be discretion in the application of the RIT-T, with TNSPs potentially providing limited information and with most parties lacking the depth of information or the technical capability to act as a check on TNSP investment plans.[191]

- There is considerable, perhaps insurmountable, complexity and uncertainty in trying to quantify costs and benefits of transmission investment, particularly competition and options benefits.[192]

- It was contended that market price signals should be incorporated into the cost-benefit assessment in the RIT-T, and that there is a clear market price signal in the case of inter-regional congestion that should be recognised. It was suggested that market revenue is a primary concern for generators and that the impact of augmentations on generator contractual positions is not considered in the RIT-T.[193]

A number of stakeholders noted that, even if a transmission augmentation was capable of passing the RIT-T, there is no compulsion on a TNSP to construct it. Therefore, rather than ensuring that all economic investments are progressed, the RIT-T prevents investment in uneconomic projects.[194]

However, other stakeholders disagreed, noting the moral suasion provided by the NTNDP and the LRPP and questioning why TNSPs might not be willing to apply the RIT-T to investments producing net market benefits. It was suggested that, as long as the regulatory rate of return is sufficient and/or the incentives for good service performance are attractive, TNSPs should be willing to invest in projects justified on market benefits grounds.[195] SP AusNet suggested that experience in Victoria - where all augmentations must be justified on market benefits grounds - does not suggest that there would be any particular challenges in applying the RIT-T to proposed network augmentations that are not required to meet a specific reliability standard.[196]

Finally, Powerlink noted that the consultation timelines in the RIT-T are longer than for previous regulatory test, and suggested that changes that shorten, rather than extend, these timelines should be sought.[197]

191 AEMO, Issues Paper submission, pp. 9-11; Alinta, Issues Paper submission, p. 17.

192 EUAA, Issues Paper submission, p. 12; Infigen, Issues Paper submission, p. 5; Origin, Issues Paper submission, p. 2; TRUenergy, Issues Paper submission, p. 2.

193 MEU, Issues Paper submission, p. 30; NGF, Issues Paper submission, p. 8.

194 AEMO, Issues Paper submission, p. 9; International Power, Issues Paper submission, p. 19.

195 Grid Australia, Issues Paper submission, p. 21; Northern Group, Issues Paper submission, p. 18.

196 SP AusNet, Issues Paper submission, p. 7.

197 Powerlink, Issues Paper submission, p. 1.

Commission's current views

The Commission notes the issues raised by stakeholders, while also noting the very short period that the RIT-T has been in place. The Commission understands that no RIT-T assessments have been completed to date.

The Commission considers that there are aspects of the RIT-T that may require further consideration, while being cognisant that the RIT-T is still in its infancy. In particular, this is likely to include the effectiveness with which competition benefits may be quantified for assessment. The Commission is concerned that the perceived complexity of such quantification may lead to competition benefits not being considered in some RIT-T assessments.

7.3.3 National planning and inter-regional augmentation

In the Issues Paper, we highlighted the recent introduction of the NTP function (which commenced operation as part of AEMO on 1 July 2009) and its role in identifying investments to achieve the efficient development of the grid on a national basis through publication of the annual NTNDP. The first full NTNDP was published in December 2010. In response, a number of stakeholders made comments specifically about national planning and inter-regional transmission augmentations.

A number of stakeholders suggested that the regional roles of TNSPs may lead, despite the establishment of the NTP, to ineffective inter-regional service provision. Some of these stakeholders contended that accountability for inter-regional planning is unclear as no one entity has the responsibility to identify and invest to meet the inter-regional needs of the NEM.[198] Other stakeholders noted similar views regarding the risks of multiple network planners across the NEM potentially not adopting a national focus and the regulatory regime not allowing the AER, when reviewing the revenue allowance for a TNSP, to consider whether investments should instead be made on another TNSP network.[199]

Some stakeholders considered that, although this lack of a national focus had not been a major issue to date, the more dispersed pattern of generation likely in the NEM going forward would mean that planning would be likely to take a greater national dimension.[200]

One stakeholder - TRUenergy - contended that the NEM has failed to deliver a sufficient level of interconnector capacity in the past decade, although it considered that the NTP will help address this.[201] Others suggested that inter-regional developments based on market benefits have not occurred because of similar fuel costs

198 International Power, Issues Paper submission, pp. 11-13; MEU, Issues Paper submission, p. 27.

199 AEMO, Issues Paper submission, p. 12; DPI, Issues Paper submission, pp. 6-7.

200 DPI, Issues Paper submission, p. 5; EUAA, Issues Paper submission, pp. 10-11.

201 TRUenergy, Issues Paper submission, p. 4.

in adjacent regions and the difficulty in quantifying competition benefits under the regulatory test.[202]

However, some stakeholders considered that a greater level of interconnection was warranted, and expressed concerns as to the ability of the NTP to significantly improve these outcomes. Origin doubted whether the RIT-T is able to facilitate the efficient and timely augmentations that confer inter-regional benefits, given the difficulties in quantifying costs and benefits. It was further noted that competition benefits and option value will not form part of AEMO's analysis when assessing transmission augmentations, despite being part of the RIT-T, and it was questioned as to whether this will mean that certain projects will not be identified in the NTNDP and therefore further analysed by TNSPs.[203] The EUAA was sceptical that AEMO's national studies have had or will have any meaningful impact on TNSP's investment plans.[204]

A small number of stakeholders commented on the LRPP, and expressed quite divergent views. Infigen supported the use of the LRPP as a mechanism for triggering cost-benefit assessments of potential projects when TNSPs are not responding to a material problem in a timely manner,[205] while AEMO questioned the value of the LRPP with the NTP arrangements now in place.[206]

In contrast, a number of other stakeholders considered that there has been insufficient time to determine the effectiveness of the current frameworks, including the RIT-T, NTP and LRPP.[207]

Commission's current views

The Commission notes the issues raised by stakeholders, while also noting the very short period that the existing framework has been in place.

The NTP and LRPP are designed to provide checks and balances on TNSPs in order to promote an efficient level of investment. The Commission notes the concerns raised by some stakeholders, and intends to give these further consideration. However, in some cases, the Commission suggests that these may reflect unrealistic expectations of what will or can be delivered by the NTP. For instance, for the analysis in the NTNDP of potential transmission augmentations to replicate a full RIT-T would likely involve a great amount of resource and time. Rather, the Commission considers that the NTNDP should provide a guide for more detailed assessments to be undertaken by TNSPs. The NTNDP will therefore inform TNSP APRs, and vice versa, but TNSP investment plans justifiably may not precisely match the investments identified in the NTNDP.

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202 EUAA, Issues Paper submission, p. 10; Infigen, Issues Paper submission, p. 5; Northern Group, Issues Paper submission, p. 17.

203 Origin, Issues Paper submission, pp. 5-6.

204 EUAA, Issues Paper submission, p. 10.

205 Infigen, Issues Paper submission, p. 5.

206 AEMO, Issues Paper submission, p. 11.

207 CEC, Issues Paper submission, p. 6; EnergyAustralia, Issues Paper submission, p. 6; ENA, Issues Paper submission, p. 1, Grid Australia, Issues Paper submission, pp. 6-7.

7.3.4 Planning information and proactive planning

In the Issues Paper, we asked whether the current transmission planning framework adequately provides reliable information to TNSPs on when and where to invest, or when to defer or avoid investment, and whether there is a case that additional market-based signals might be beneficial.

In response, two stakeholders suggested that a shortcoming of the current planning arrangements is the formulation of demand forecasts.[208] One of these stakeholders - the Northern Group - saw existing frameworks as being satisfactory in most areas except for this particular issue. It commented that:[209]

> "It is apparent [...] that the SOO/ESOO forecasts have systematically over-stated actual demand since the NEM commenced, both on a system-wide and on a regional basis. It appears that this is at least in part a consequence of the fact that the demand forecasts are based on economic growth forecasts that have themselves been consistently too high."

It further suggested that:[210]

> "While TNSPs may have an incentive to overstate demand in order to justify more transmission investment, as a not-for-profit body, AEMO does not have such an incentive. Similarly, the private consultants hired to prepare the economic growth forecasts do not benefit from over-estimating demand. It may be that the culture within AEMO is excessively conservative or risk-averse. But for whatever reason, we consider that the demand forecasting methodology needs to be improved to avoid an unnecessary over-build of transmission."

Other stakeholders addressed the possibility of using additional, market-based signals in planning. While AGL did not see the need for further market signals in planning,[211] other stakeholders supported a greater role for information provided by the market and market signals in determining transmission investment.[212]

In particular, the DPI suggested a benefit of a regime of firm financial transmission rights would be the additional information that would be revealed through the sale of these rights:[213]

> "Market based signals could be generated from the sale of contractual instruments such as financial transmission rights. The sale of long term

208 Alinta, Issues Paper submission, p. 9; Northern Group, Issues Paper submission, p. 17.

209 Northern Group, Issues Paper submission, p. 17.

210 Northern Group, Issues Paper submission, p. 18.

211 AGL, Issues Paper submission, p. 19.

212 DPI, Issues Paper submission, p. 5; Gallaugher, Issues Paper submission, p. 3; NGF, Issues Paper submission, p. 10.

213 DPI, Issues Paper submission, pp. 5-6.

> financial transmission rights which provide generators with access to the transmission network would enhance the information that network planners rely upon to make decisions on whether to augment the network (i.e. through the RIT-T process). Under such an approach, rights to use transmission would be sold to generators (through an efficient allocation process) several years in advance. The market based information provided through the sales of these rights could be critical at a time of significant uncertainty for the market in informing the need for network investment."

It was noted that the sale of rights might also assist the AER in evaluating the capital expenditure programs of TNSPs.[214]

However, other stakeholders suggested planning which responds to market requests for access may present problems with respect to timely delivery of transmission infrastructure and that there may therefore be a case for transmission development to lead generation development. Having said that, one stakeholder in question - AGL - noted that this could be problematic,[215] while the NGF highlighted its concerns that a proactive planner would be reinstituting a central planner mindset which would detract from overall market driven efficiency.[216]

Commission's current views

The Commission notes the views expressed by stakeholders. In particular, the Commission notes the importance of demand forecasts in the transmission planning process, and intends to examine the accuracy of these forecasts. However, the Commission is cognisant that some level of over-forecasting may be a rational response to the asymmetric risk associated with forecasting, i.e. there are arguably greater risks in terms of reliability associated with under-investing in the network.

The Commission also notes the possible benefits that might be given by transmission rights in terms of providing additional information for transmission planning. The sale of these rights would provide certainty over the usage of the transmission system, and could therefore reduce the risk of transmission assets being under-utilised. However, the Commission notes that the implementation of a firm transmission rights regime would represent a very significant change to the current market arrangements, and that a broad range of other costs and benefits would need to be assessed in considering any such move.

Finally, the Commission notes the comments relating to the potential for proactive development of the shared transmission network ahead of demand for transmission services. The Commission has recently released its Draft Determination for the Scale Efficient Network Extensions Rule change request.[217] In this draft determination, the Commission explained its assessment that the costs of customers bearing potential

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214 DPI, Issues Paper submission, p. 6.

215 AGL, Issues Paper submission, p. 20-21.

216 NGF, Issues Paper submission, p. 10.

217 AEMC 2011, *Scale Efficient Network Extensions*, Draft Rule Determination, 10 March 2011, Sydney.

stranding risks associated with the pre-emptive over-building of network extensions outweighed the likely benefits that might result from the capture of scale economies.

The Commission is therefore concerned that any proactive investment in the shared network might be likely to encounter similar risk allocation issues. However, the Commission also notes that there might be potential for a greater level of proactive planning and preparation to be undertaken.

7.3.5 Institutional arrangements

In submissions to the Issues Paper, a number of stakeholders noted the unusual feature of the NEM in enabling different institutional arrangements for transmission planning to exist in parallel.[218]

In New South Wales, Queensland and Tasmania, responsibility for planning lies with TNSPs, and the TNSP will own and operate any resulting augmentations. In contrast, in Victoria, network planning is undertaken by AEMO. AEMO runs competitive tenders to determine who will undertake planned network augmentations. In South Australia, the planning process is largely undertaken by the TNSP, although AEMO provides inputs in the form of supply and demand forecasts.

Stakeholders expressed a range of views about these arrangements.

The EUAA suggested that the Victorian approach of separating planning and major asset procurement from asset ownership delivers favourable cost outcomes.[219] Some others proposed that consideration should be given to whether AEMO's planning role should be broadened to make planning and investment decisions on a national basis. Such stakeholders considered that this would lead to an increased national focus in planning and that, with an independent not-for-profit planning body with no commercial interest in decisions, there would be limited risk of distorted planning and investment decisions.[220] One of these stakeholders - the DPI - noted, that under a firm access rights regime, AEMO could sell rights on behalf of TNSPs, and contract with TNSPs for the delivery of investment.[221]

In contrast, other stakeholders considered that the current transmission planning arrangements in the other jurisdictions are broadly reasonable, operating at a regional and a NEM wide level and having become increasingly transparent and comprehensive since the inception of the NEM.[222] A view was expressed by Grid Australia that the party responsible for transmission service delivery should also be

218 See, for example, Table 1, AEMO, Issues Paper submission, p. 5.

219 EUAA, Issues Paper submission, p. 8.

220 AEMO, Issues Paper submission, p. 28; Alinta, Issues Paper submission, p. 15; DPI, Issues Paper submission, p. 7; Infigen, Issues Paper submission, p. 5; MEU, Issues Paper submission, p. 31.

221 DPI, Issues Paper submission, p. 7.

222 Northern Group, Issues Paper submission, p. 15.

responsible for transmission investment decision making,[223] and it was suggested that this was consistent with the COAG agreed principle that:[224]

> "accountability for jurisdictional transmission investment, operation and performance will remain with transmission network service providers."

In a paper responding to the Issues Paper submissions, Grid Australia further suggested, if it is accepted that incentive regulation promotes superior outcomes to central planning, then it is logical to conclude that the current arrangements in Victoria are suboptimal.[225] This is because, as a not-for-profit entity, AEMO has no capacity to respond to financial incentives, and Grid Australia contended that a clear majority of stakeholders, including AEMO, support the use of financial incentives to encourage efficiency improvements.[226] Grid Australia therefore suggested that the result of the current regime in Victoria is that there is no scope for incentive regulation to encourage:

- innovation in augmenting the network to meet service objectives;
- optimal trade-offs between network and non-network options and between investment and operating and maintenance measures; and
- small investments and other schemes to improve the transfer capacity of the current network assets.

Two stakeholders proposed the adoption of single transmission owner and operator across the NEM. One of these, Alinta, suggested that the division of the NEM network between six TNSPs might be affecting the industry's natural scale economies, potentially producing a level of costs that are higher than they otherwise should be.[227]

The other stakeholder - the MEU - expressed a view that:[228]

> "...the NEM will be well-served by the creation of a national grid body to plan, build and operate inter and intra [regional] transmission networks under a uniform, coherent and consistent set of legislation and regulations. This concept, which was initially raised in 1992 by then Prime Minister, Paul Keating, deserves a reinvestigation. The fact that current arrangements, guidelines and procedures cut across a myriad range of national, State-based legislation and regulations and asset ownership is considered to be less efficient."

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223 Grid Australia, Issues Paper submission, p. 19.

224 MCE, *Terms of Reference - AEMC Transmission Frameworks Review*, p. 2.

225 Grid Australia, Issues Paper supplementary submission, p. 13.

226 Ibid, p. 5.

227 Alinta, Issues Paper submission, pp. 7-8.

228 MEU, Issues Paper submission, p. 19.

Commission's current views

The Commission notes the views of stakeholders in relation to the institutional arrangements for network planning across the NEM. The Commission also notes the requirement in the MCE's terms of reference for the review that it must have regard to certain COAG principles, including that described above.

The Commission considers that the concept of a single transmission owner and operator across the NEM might have merit in terms of realising scale economies and promoting national consistency. Given there are currently five TNSPs of significant scale in the NEM with a mix of private and government ownership, implementing such a model might, however, be a challenging task.

8 Connections

8.1 Introduction

This chapter covers the final workstream identified by the Commission for further investigation, which relates to the current connection arrangements in the NEM.

In large part due to the broad ranging concerns raised by stakeholders, the connections workstream will consider issues beyond those raised in the Issues Paper, for reasons outlined below.

8.2 What is the issue?

The Issues Paper sought to broadly canvass the efficacy of the current connections regime, and highlighted a risk that TNSPs may not be sufficiently responsive and flexible to the anticipated increase in new connections. In particular, the connections regime will need to ensure that TNSPs are able to connect new generation plants to the transmission system at an efficient price with an agreed level of service and quality in a timely manner.[229]

The Issues Paper noted that the regulatory regime applying to connections allowed for negotiation between TNSPs and connecting parties, as these parties are viewed as having sufficient countervailing power to negotiate efficient connection outcomes with TNSPs. However, in light of the potential increasing demand for connections, the Issues Paper questioned whether the current arrangements for the connection of generators and large end-users reflect the needs of the market. The paper also asked, to the extent that more fundamental reforms to transmission frameworks are considered under the review, whether it would be appropriate to more broadly revisit connection arrangements.

A clear view emerged from submissions that, irrespective of any fundamental reforms that may be considered to transmission frameworks under the review, there was a definite need to revisit current connections arrangements, as they did not meet the needs of the market. In particular, some stakeholders considered that this was because generators and large end-users were unable to effectively negotiate technically and economically efficient outcomes.

Since the publication of the Issues Paper, the Commission has also given further consideration to connection arrangements as part of the process of assessing the SENEs Rule change request. The Commission has made a draft determination[230] on the SENEs

229 AEMC 2010, Transmission Frameworks Review, Issues Paper, 18 August 2010, Sydney, pp. 30-32.

230 AEMC 2011, Scale Efficient Network Extensions, Draft Rule Determination, 10 March 2011, Sydney.

proposal, but as part of the assessment process it has identified a number of wider issues relating to connection arrangements for consideration in this review.[231]

From reviewing submissions to the Issues Paper and through its own further considerations, the Commission has concluded that there is a lack of clarity surrounding connection arrangements, and, in particular, how new assets required for the purpose of connection should be classified and funded.

Box 8.1 Context for investigation of connection arrangements

The connection and maintenance of load and generation to the transmission network requires two different types of transmission services: connection services and shared transmission services. Connection services describe the 'entry' and 'exit' points to the transmission network which are relevant for generators, large end-users and distribution networks. Shared transmission services describe the service provided to load and generators for the conveyance of electricity across the transmission network.

There are a variety of physical assets that underpin the delivery of these transmission services. For instance, if a generator requires connection to the transmission network, and a terminal station with sufficient capacity already exists at the location where the generator wishes to connect, the type of underlying asset required for their connection may be limited to a connection asset at the terminal station. However, where a terminal station does not already exist in a suitable location, there may be an additional requirement to construct a terminal station as an augmentation to the shared transmission network.

Where a generator's connection to the network is assessed as impacting on the reliability and security parameters of the transmission network, an augmentation to the transmission network may be required.

Therefore, considering the various aspects of connecting generators and load to the transmission network requires a clear distinction between two essential but inclusive concepts: the capital works required for the connection of generators, distribution and large end-users to the transmission network, and the services provided by TNSPs in order to facilitate a connection or provide a transmission service to maintain connection to the transmission network.

The lack of clarity stems largely from the fact that Chapter 5 of the Rules primarily refers to the *process* for connection, where as Chapter 6A regulates the provision of transmission *services* and implicitly assumes that an asset already exists. Therefore, the treatment of new assets for the purpose of connection is open to interpretation by TNSPs. The Commission understands that TNSPs may take different approaches to the construction of new assets to facilitate connections and may draw a distinction

231 In particular, see: AEMC 2010, Scale Efficient Network Extensions, Options Paper, 30 September 2010, Sydney.

between the classification (and therefore treatment) of the construction of assets and the services that are provided by the assets once constructed.

The following sections first set out the types of transmission services defined in the Rules, before discussing the various issues caused by the inconsistencies between the two Chapters of the Rules.

8.2.1 Types of transmission services

The Rules define three different types of transmission services: prescribed, negotiated, and non-regulated. The diagram below gives a general description of the characteristics of each type of transmission service according the definitions in Chapter 10 of the Rules.

Figure 8.1 Categorisation of transmission services and their respective characteristics

Transmission services

	Prescribed	Negotiated	Non-regulated
Characteristics of service	Shared transmission service *- meets standard network performance requirements*	Shared transmission service *- exceeds or does not meet standard network performance requirements*	Neither: prescribed nor negotiated transmission service
	Connection services- for other Network Service Providers	Connection services- for Transmission Network Users	
	Above-standard system shared transmission service	Use of system services (i.e. under clause 5.4A)	
	Required by jurisdictional legislation to meet security or other requirements		
	Economic regulation and funding of services		
	TNSPs are obligated to provide service	TNSPs are obligated to provide service	TNSPs are not obligated to provide service
	Subject to economic regulation under Chapter 6A	Subject to economic regulation under Chapter 6A according to the TNSP's negotiating framework	Not subject to economic regulation under Chapter 6A including the negotiating framework
	AER approves pricing methodology and caps revenue for each TNSP during the regulatory reset period for transmission determinations	AER approves negotiating framework for each TNSP during the regulatory reset period for transmission determinations	
	Service charges are levied to transmission system load; costs are passed through to consumers	Service charges are levied to users of the transmission system only	

Prescribed transmission services

Prescribed transmission services largely relate to 'shared transmission services', but also include 'connection services' that apply to other 'Network Service Providers' (i.e. connections to distribution networks or other TNSPs), other than Market Network Service Providers (MNSPs).[232]

232 Connection services provided to some generators in relation to existing connections are also treated as prescribed transmission services pursuant to the 'grandfathering' provisions in clause 11.6.11 of the Rules.

A shared transmission service is a prescribed transmission service when it either meets standard network performance requirements specified in jurisdictional electricity legislation or Schedules 5.1 or 5.1a of the Rules, or is an 'above-standard system shared transmission service'. To be classified as an 'above-standard shared transmission service', the service must exceed the standard requirements as a consequence of investments that have system-wide benefits.[233]

In addition, because of the reliability and security elements of shared transmission services, and their relationship to the shared transmission network, generators and users of the transmission system are not able to negotiate service delivery outcomes for prescribed services.

Negotiated transmission services

Negotiated transmission services relate to shared transmission services; and connection services that apply to 'Transmission Network Users' (such as generators, large end-users and MNSPs). A shared transmission service is a negotiated transmission service when it either exceeds or does not meet standard network performance requirements specified in jurisdictional electricity legislation or Schedules 5.1 or 5.1a of the Rules. This is a key distinction in describing the difference between a shared transmission service that it is either a prescribed or negotiated transmission service.

For negotiated transmission services, a TNSP has an obligation to provide negotiated transmission services according to their negotiating framework and negotiated transmission service criteria that are approved by the AER. These documents provide high level principles and guidelines for the negotiation process between TNSPs and Transmission Network Users. An objective of these documents is to provide adequate guidance such that generators and users can effectively negotiate technically and economically efficient connection outcomes.

Clause 6A.9.5 of the Rules requires that TNSPs must develop a negotiating framework that includes provisions relating to:

- the terms and conditions of access for negotiated services;
- provision of commercial information from both the generator/user and the TNSP;
- identification and information on reasonable costs;
- demonstration that the charges are cost reflective;
- timeframes for commencing, progressing and finalising negotiations;
- the dispute resolution process;

233 The Commission has previously noted that, while the term 'system-wide benefits' is defined, the Rules do not prescribe a specific test to demonstrate such benefits, and that there is therefore not a formal link with the RIT-T. See: AEMC 2010, Scale Efficient Network Extensions, Options Paper, 30 September 2010, Sydney, pp. 21 and 26.

- costs associated with progressing the connection application; and
- the potential impacts of the negotiated transmission service.

Non-regulated transmission services

A non-regulated transmission service is defined as 'a transmission service that is neither a prescribed transmission service or a negotiated transmission service'.[234] Non-regulated transmission services are not subject to economic regulation or the negotiating framework under Chapter 6A. In effect, non-regulated transmission services are provided for and delivered on a commercial basis between TNSPs and generators or users.

8.2.2 The definition of connection services and the impact on the categorisation of transmission services

Connection services provided for under a negotiated transmission service relate to Transmission Network Users only, typically generators, large end-users and MNSPs. The definition of 'connection services' under Chapter 10 for negotiated transmission services describes a connection service as being 'connection services that are provided to serve a Transmission Network User, or group of Transmission Network Users, at a single transmission network connection point' and excludes those services provided for and between Network Service Providers (NSPs).[235]

'Transmission network connection point' is defined as the 'connection point on a transmission network'. 'Connection point' is defined as 'the agreed point of supply established between Network Service Provider(s) and another Registered Participant'.

Therefore, the boundary of a transmission network for the provision of connection services is in part determined by where a TNSP defines the 'agreed point of supply'. The location of the connection point can affect which part of the services provided by the TNSP in relation to a connection are treated as negotiated transmission services or non-regulated transmission services.

The broader implication of this is that the classification of transmission services, in particular negotiated transmission services, are not provided for in a systematic manner. Therefore, the categorisation of transmission services may indeed vary across jurisdictions of the NEM depending on where a TNSP determines the 'agreed point of supply' is. The Commission has previously noted that the categorisation of transmission services, specifically for extensions and augmentations, in part depends on the individual practices of TNSPs, which varies across jurisdictions.[236]

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234 See NER Chapter 10.

235 Where neither NSP is a MNSP.

236 AEMC 2010, Scale Efficient Network Extensions, Options Paper, 30 September 2010, Sydney, p. 29.

8.2.3 'Augmentations' and 'extensions' to the shared network required as part of the connection process

Depending on the Connection Point defined, a connection may require 'augmentation' or 'extension' of the shared network. While these terms are defined in either the Rules (extension) or the NEL (augmentation), in practice the distinction between the two is blurred. For example, they appear to be used interchangeably in the Rules and, similarly, in submissions to this review.

The types of augmentations or extensions to the shared network that may be required to facilitate a connection can vary greatly and the regulatory treatment of different types of augmentations or extensions may also vary. For example:

- an augmentation to the shared network may be required in order to allow a new connection without compromising the levels of quality that the TNSP is required to provide to existing connected parties under the Rules;[237]
- augmentations and extensions may also be required in accordance with clause 5.4A;[238]
- a connecting party may require the construction of an additional element of the shared network such as a new terminal station in order to allow it to connect to the existing shared network.

The Rules do not clearly distinguish between these different scenarios and their regulatory treatment. In particular, the only type of extensions or augmentations that are referred to in the definitions of negotiated and prescribed transmission services are augmentations under clause 5.4A.

Similarly, Chapter 5 refers to 'funded augmentations’ (which are defined in Chapter 10 as a 'transmission network augmentation for which the Transmission Network Service Provider is not entitled to receive a charge pursuant to Chapter 6A’). Funded augmentations are not referred to in the definitions of prescribed or negotiated transmission services that are used in Chapter 6A. It is therefore not clear which service they should fall under, and therefore how negotiations for their construction should take place.

237 Clause 5.3.5 of the Rules regulates the Offer to Connect and requires TNSPs to assess the impact of a connection on other users of the transmission network to determine the extent and costs of augmentations that are required in order to maintain levels of service and quality subsequent to the new connection.

238 See chapter 4 of this Directions Paper for further detail on issues associated with clause 5.4A. In some cases stakeholders have raised concern that the provisions under this clause are not effectively employed by market participants as they do not adequately outline the conditions for negotiating various access standards. Therefore, the Commission understands that while extensions and augmentations may be required as part of the provision under clause 5.4A the extent to which these provisions have been utilised, and are therefore effective, is unclear.

8.2.4 Distinction between connection 'services' and connection 'assets'

In order to connect to the transmission network a generator or large end-user may require the construction of capital works such as an extension, a terminal station, or an augmentation to upgrade the capacity of the transmission lines so that reliability and security standards are maintained.

However, as noted, Chapter 6A and the related definitions in Chapter 10 focus on 'services' and do not provide clarity as to the treatment of the works that are required to construct the underlying assets. For example, the Commission understands that some TNSPs may draw a distinction between the regulatory treatment of:

- the construction of an extension or augmentation; and
- the services that are provided using the extension or augmentation once it is constructed.

In addition to the lack of clarity on the difference in regulatory treatment of connection assets and services, it is also unclear whether there is an express obligation that compels a TNSP to construct a connection asset as part of the connection service.

Clause 5.2.3(d)(1) of the NER requires that a TNSP review and process connection applications to connect or modify a connection including entering into a connection agreement with a connection party. The obligation to review and process a connection application extends to the TNSP's part of the 'national grid'. By implication of the definition of 'national grid' this also includes connection assets.

However, TNSPs are generally not obliged to provide extensions to the transmission network.[239] Some TNSPs could potentially consider the construction of new assets that do not pass the RIT-T, and recovery of associated costs, as being outside of the scope of the Rules and therefore not economically regulated. As noted, there is no clear linkage between the concept of a 'funded augmentation' and the economic regulation of transmission services under Chapter 6A.

The Commission understands that in practice in some jurisdictions, TNSPs and connecting parties agree that the connection applicant will construct the assets required for the connection, extension or augmentation itself and then ‘gift’ these to the TNSP. The TNSP will then provide transmission services using those assets.

8.2.5 Contestability in the provision of connection assets and services

In practice, there appears to be an understanding amongst some participants that if the construction of an asset can be deemed to be a contestable service, then it is considered not to be subject to economic regulation. However, the Rules are not clear on this issue.

239 See NER clause 5.3.6(k).

Contestability of a connection service is referred to in Chapter 5 of the Rules as part of the Connection Enquiry and Connection Application process. A Network Service Provider is required to assess whether any service they propose to provide is contestable in that jurisdiction.[240] Where a transmission service is contestable, a connection applicant may seek additional offers.[241]

'Contestable' is defined in Chapter 10 as a transmission service which is permitted by the laws of the relevant jurisdiction to be provided by more than one TNSP as a contestable service, or on a competitive basis. However, contestability is not a criterion for defining whether a transmission service, such as a connection service, is prescribed, negotiated or non-regulated. There is therefore no direct linkage between an asset being contestable under Chapter 5 and the service provided being non-regulated under Chapter 6A.

8.2.6 Application of the negotiating framework to the connection process

The connection process is governed by Chapter 5 of the Rules, which regulates aspects of the technical and contractual arrangements and obligations that facilitate connection to the transmission network. The connection process ensures that both the connection applicant and the TNSP consider the technical, security and reliability implications of connections to the network, including the impact on other network users.

Through analysis of the AER approved negotiating frameworks of TNSPs (available on the AER website) it appears in practice TNSPs' negotiating frameworks apply during the stages of the connection process highlighted in the table below. Notably, the negotiating framework does not appear to apply to the initial stages of a connection process for the 'Connection Enquiry' and the 'Response to Connection Enquiry'. There is therefore ambiguity as to how the connection process is regulated in respect of these steps, and it is not clear what level of recourse is available to connection applicants.

Table 8.1 The connection process

Connection Enquiry (clause 5.3.2)	*Response to Connection Enquiry (clause 5.3.3)*	*Application for Connection (clause 5.3.4)*	*Preparation of Offer to Connect (clause 5.3.5)*	*Offer to Connect (clause 5.3.6)*	*Finalisation (clause 5.3.7)*
Applicant makes enquiry to TNSP	TNSPs must liaise with other NSPs	Applicant makes Application to Connect and pays application fee	TNSP prepares Offer to Connect	Offer must be made within time period specified in preliminary program	Applicant can accept Offer to Connect following negotiations

240 See NER clause 5.3.3.

241 See NER clause 5.3.4.

8.3 Areas for further consideration

Predominant themes and organisation of issues for further consideration

In submissions to the Issues Paper, stakeholders raised numerous matters associated with the connection arrangements that in their opinion require attention. The issues raised ranged from technical parameters associated with fault levels for distributors,[242] the valuation of Network Support and Control Ancillary Services (NSCAS) in connection agreements,[243] and TNSP resourcing towards negotiated transmission services,[244] to much broader issues associated with the negotiating framework such as the interaction of Chapters 5 and 6A of the NER;[245] and more broadly the categorisation of transmission services.[246]

However, a strong view has emerged across the majority of submissions that there is an imbalance in bargaining power when negotiating with a monopoly service provider during the connection process or contract variation.[247] Consequently, generators and users consider that they are unable to negotiate technically and economically efficient connection outcomes that reflect their needs.

Some of the perceived causes of limited bargaining power identified in submissions include issues specific to the connection and negotiation process, the interaction between Chapters 5 and 6A in describing the provision of various elements of transmission services, and the individualised practices of TNSPs. For stakeholders with interests in Victoria, the lack of negotiating power is further compounded by the connection arrangements in that state, namely the tripartite contractual arrangements that govern the provision of connections services.

To address these issues the Commission has organised issues according to the table below:[248]

242 EnergyAustralia, Issues Paper submission, p. 9.

243 Alinta Energy, Issues Paper submission, p. 24.

244 NGF, Issues Paper submission, p. 20.

245 LYMMCo, Issues Paper submission, p. 30; Origin, Issues Paper submission, p. 8.

246 NGF, Issues Paper submission, p. 14; Northern Group, Issues Paper submission, p. 30; AEMO, Issues Paper submission, p. 15; International Power, Issues Paper submission, p. 30.

247 Primarily generators (including renewable generation) and large end users of the transmission system. EnergyAustralia provided a submission that focussed on the relationship amongst the various types of Network Service Providers.

248 Due to the inter-related nature of transmission frameworks, some issues raised by stakeholders in relation to the connection regime have implications for other matters for consideration under the Review. Issues raised in relation to section 5.4A of Chapter 5 (AGL, Issues Paper submission, p. 27), access standards more generally (International Power, Issues Paper submission, p. 30; LYMMCo, Issues Paper submission, p. 30; TRUenergy, Issues Paper submission, pp. 6-7), firm transmission rights (DPI, Issues Paper submission, p. 7) and deep connections will be investigated in the Review through the Access and Network Charging workstreams.

Organisation of connection issues

Negotiating issues	Chapters 5 & 6A	Jurisdictional issues	Complexities with the Victorian regime
Negotiating process and framework	Integration of NER Chapters 5 & 6A	National consistency and efficiency losses	Contractual arrangements
Connection process	Contestability		Third party liabilities
	Categorisation of transmission services		Obligations on generators in the shared network
	Treatment of augmentations and extensions required in relation to the provision of connection services		

8.3.1 Negotiating framework and the connection process: transparency of costs, timing and technical parameters

A strong view has emerged from submissions on the limited bargaining power of generators and users in negotiating with TNSPs during the connection process, including for the provision of negotiated transmission services.[249] For example, Infigen noted that in their experience "it is very difficult to negotiate with...monopoly service providers such as NSPs, even for negotiated services" and that "NSPs have 99% of the leverage in new connection negotiations".[250]

AGL supported this argument and note that "no matter how big or large the suppliers are and even when acting as a group they are unlikely to be a counterweight when dealing with a monopoly".[251] The MEU cautioned that the "AEMC should take great care in assuming that large generators and end users have the ability to offset the power of monopoly".[252]

Some stakeholders were of the view that elements of both the negotiating framework and connection process should be revisited to improve the current imbalance by enhancing the transparency and clarity of some provisions. Conversely, others concluded that in order to effectively redress the imbalance, the role of TNSPs should

249 Infigen, Issues Paper submission, p. 8; AGL, Issues Paper submission, p. 28; EUAA, Issues Paper submission, p. 8, MEU, Issues Paper submission, p. 37.

250 Infigen, Issues Paper submission, p. 8.

251 AGL, Issues Paper submission, p. 28.

252 MEU, Issues Paper submission, p. 37.

be limited and solutions should be sought that devolve as much power as possible to service providers in a competitive market.[253]

Negotiating framework and process

Many stakeholders concluded that the negotiating framework does not facilitate technically and economically efficient outcomes. Two issues were noted in particular:

- the absence of an express obligation on TNSPs to investigate a range of technical connection options; and
- a perceived lack of transparency of the costs associated with connection services including augmentations or extensions to the transmission network.

Some stakeholders noted that the NER does not compel TNSPs to investigate a range of connection options as is required for augmentations. Consequently, generators and users consider that they may be presented with connection options by TNSPs that are beyond their technical requirements, or not fit for purpose. Some stakeholders perceive that connection assets and services have been designed to meet the standards required for regulated assets, and that has resulted in a costly solution for them.[254] However, other stakeholders noted that sometimes the connection options proposed by TNSP can also reflect jurisdictional requirements on technical standards.[255]

Transparency of the costs associated with connection services provided by TNSPs was also raised as an issue by certain stakeholders. Chapter 6A, Part D of the Rules requires TNSPs to identify and provide information on how 'reasonable costs' are determined, and to demonstrate that any charges associated with the negotiated transmission service are cost reflective. In the experience of these stakeholders however, these provisions do not deliver adequate transparency to allow generators and users to effectively negotiate outcomes. In addition, it was submitted that there is also inadequate transparency of the costs associated with an 'Application for Connection'. In summary, relevant stakeholders submitted that greater proof should be required of TNSPs to establish that the costs associated with a connection service as described under an 'Offer to Connect' are reasonable.[256]

Transparency of costs associated with the provision of connection services becomes especially problematic for TNSPs where extensions or augmentations are required. This is due the difficulties in ascertaining from connection agreements with TNSPs which costs are strictly attributable to the new connection, and which costs relate more broadly to the shared network.[257] In the view of some stakeholders, lack of transparency means that TNSPs have the ability to impose additional costs on

253 EUAA, Issues Paper submission, p. 9.

254 Infigen, Issues Paper submission, p. 8; EUAA, Issues Paper submission, p. 8.

255 NGF, Issues Paper submission, p. 16.

256 NGF, Issues Paper submission, p. 15; Alinta Energy, Issues Paper submission, p. 24.

257 NGF, Issues Paper submission, p. 15; International Power, Issues Paper submission, p. 30.

connection applicants that may be more appropriately recovered from users of prescribed services.[258]

Proposed solutions to this issue advocated by some stakeholders included the provision of more detailed information in regulated accounts,[259] while other stakeholders considered that an expert mediator should be introduced to facilitate negotiations between TNSPs and connection applicants on costs and technical requirements.[260]

Connection process and the provision of information

Some stakeholders submitted that greater clarity on timing and information provision is needed for the connection process. This is particularly crucial for project proponents as they determine the full feasability of a specific project.[261] These stakeholders noted that project proponents cannot accurately assess whether or not they have a feasible project until full information on costs and technical parameters (such as type and size of a connection) are factored in.

For example, the connection process requires that access standards are determined during the Application for Connection stage. For generators, access standards will be influenced by technical parameters which are generally not finalised at this (early) stage of the connection process. Therefore, the NGF submitted that greater flexibility should be built into the connection process for finalising some requirements that impact on the technical parameters of the project's design to ensure that generators able to make efficient investment decisions.[262]

For some stakeholders, access to this type of information can also assist in the competitive provision of non-regulated services and assets.[263] AEMO, as the network operator and planner in Victoria, noted that the constraints on disclosure of information has implications for promoting a coordinated approach for connection under its 'Hub Concept'.[264]

Some stakeholders also raised concerns regarding the absence of clear timeframes in the connection process for progressing connection applications. For generators and users, the delays in progressing applications sometimes resulted in inefficiencies.[265]

258 NGF, Issues Paper submission, p. 15.

259 NGF, Issues Paper submission, p. 15.

260 International Power, Issues Paper submission, p. 30.

261 NGF, Issues Paper submission, p. 16; AEMO, Issues Paper submission, p. 16.

262 NGF, Issues Paper submission, pp. 16-17.

263 NGF, Issues Paper submission, p. 16.

264 AEMO, Issues Paper submission, p. 16.

265 While the negotiating framework developed by TNSPs provides indicative timeframes for progressing each milestone under the connection process, stakeholders were of the view that this should be more explicitly provided for in the connection process under Chapter 5.

On this issue, certain stakeholders suggested that the Rules should provide more guidance regarding:[266]

- what information a connection applicant and TNSP must provide;
- who pays for the information; and
- the timing for release or provision of the information.

Commission's current views

The Commission notes the views expressed by stakeholders, and intends to give further consideration to the issues raised around the negotiation of connections.

In particular, more detailed exploration of the issues is merited for both the technical interactions during the connection process outlined above, and information and transparency requirements of the negotiation process. This may further illuminate the difficulties faced by generators and users in negotiating connection services with monopoly services providers, in order to identify possible solutions that may optimise generator and user connection outcomes.

The Commission will also consider the extent to which the provision of information by TNSPs can facilitate better or improved coordination amongst users of the transmission system for connection options. This issue takes particular precedence in light of both the draft determination for the SENEs Rule change request and AEMO's Hub Concept. Both concepts seek to efficiently connect new generation to the transmission system.

8.3.2 Chapters 5 and 6A: contestability and interaction with the shared network

Earlier in this chapter we discussed the interactions of Chapters 5 and 6A of the Rules in describing the treatment of extensions and augmentations to the transmission network and system. The ambiguity that arises from the interaction of these two chapters has direct consequences for considering a number of issues raised by stakeholders in relation to the application of the connections regime. These issues include defining the contestability of some transmission services, and whether some transmission services should be categorised as negotiated transmission services rather than non-regulated transmission services.

Contestability

Chapter 5 of the Rules requires that when TNSPs process an Application for Connection they must assess whether any service they propose to provide is contestable in the relevant jurisdiction.[267] Where the connection service provided can be procured on a contestable basis, connection applicants can seek additional offers from other TNSPs in that jurisdiction. In practice, the Commission understands that

266 NGF, Issues Paper submission, p. 16; TRUenergy, Issues Paper submission, p. 8.

267 See NER clause 5.3.3.

some TNSPs use contestability as a measure for determining the categorisation of a transmission service. In its guidelines, Grid Australia considers that contestable services are provided for as a non-regulated transmission service.[268]

A number of stakeholders suggested that the Commission should revisit the definition of contestability under the Rules for the reason that some transmission services cannot be procured on a competitive basis, and should therefore instead be provided as negotiated transmission service rather than a non-regulated transmission service.[269]

However, contestability is not a criterion for defining whether a transmission service is prescribed, negotiated or non-regulated. The effect of this discrepancy is that enhancing the definition of 'contestability' will not resolve or permit the re-categorisation of a transmission service as there is no clear link between the reference to contestability in Chapter 5 and the service classification in Chapters 6A and 10 of the Rules.

Interaction with the shared network

The extent to which augmentations and extensions to the transmission network are provided for as either prescribed, negotiated or non-regulated transmission services in the Rules is not clear and in part appears to depend on the practices of TNSPs. A clear view of the treatment of augmentations by TNSPs did not emerge from submissions, reflecting the varied practices of individual TNSPs.

However, some stakeholders noted a number of concerns in relation to how augmentations and extensions are treated. These stakeholders noted that TNSPs are not obligated to provide augmentations to the shared network.[270] Reviewing how transmission services are categorised and the interactions between Chapters 5 and 6A may provide clarity to this issue. This is particularly important when considering how augmentations to the shared network, as part of a connection process, should be characterised under the Rules.

Depending on the approach taken by TNSPs, augmentations to the shared network may be covered by the definition of negotiated transmission services as they relate to the provision of a shared transmission service, or a 'funded argumentation' that is categorised as a negotiated transmission service or a non-regulated transmission service. The Commission understands that TNSPs may also distinguish between the construction of the augmentation asset and the provision of services over the augmentation once it is constructed and forms part of the shared network. Some stakeholders submitted that charges and costs associated with augmentations to the shared network should be recovered through charges for prescribed transmission services.[271]

268 Grid Australia, Categorisation of Transmission Services Guideline, August 2010, p. 7.

269 NGF, Issues Paper submission, p. 14; Alinta Energy, Issues Paper submission, p. 24; Northern Group of Generators, Issues Paper submission, p. 30.

270 AEMO, Issues Paper submission, p. 15; NGF, Issues Paper submission, p. 13.

271 NGF, Issues Paper submission, p. 15.

Commission's current view

The Commission considers that investigating the interaction between Chapters 5 and 6A is fundamental to the connections workstream. In particular, the ambiguities highlighted in the treatment of elements related to the connection service, such as extensions and augmentations, will be an area of increasing concern as new and remote generation increases on the transmission system in response to both demand and climate change policies such as the RET.

8.3.3 Jurisdictional differences

In submissions, a number of stakeholders expressed concern with the lack of national consistency in the application of connections arrangements.[272] The persistence of jurisdictional differences were perceived to be a cause of inefficiencies in the delivery of connection services, and is especially problematic for generators and users that operate in numerous NEM jurisdictions. This is because jurisdictional differences in the connection process limit the scope to learn from a connection process through repeated lessons as the connection processes varies across jurisdictions.

Some stakeholders contended that national inconsistency is partly caused by a lack of clarity of provisions in the Rules for connection arrangements.[273] Other stakeholders considered that jurisdictional differences are largely due to different jurisdiction-specific requirements.[274]

The impact of jurisdictional differences in relation to broader efficiency objectives associated with the NEM has been an ongoing issue in energy market reform and was first identified for major reform in the Parer Report to COAG in 2002.[275]The contribution of jurisdictional differences to inefficiencies in the energy market objectives was again flagged by the Energy Reform Implementation Group (ERIG) in its 2007 report to COAG on energy reform.[276] ERIG noted that differing state regulatory arrangements, different licencing regimes, guidelines and codes of practice ultimately increase costs to customers.

Commission's current view

The Commission considers it would be useful to determine the magnitude to which jurisdictional regulatory differences contribute to an inefficient connections regime. The extent to which jurisdictional differences can be separated from requirements of the Rules and the practices of TNSPs will provide significant insight into the manner in

272 LYMMCo, Issues Paper submission, p. 30; AEMO, Issues Paper submission, p. 18; EUAA, Issues Paper submission, p. 8.

273 LYMMCo, Issues Paper submission, p. 30.

274 AEMO, Issues Paper submission, p. 17.

275 Council of Australian Governments: Towards a Truly National and Efficient Energy Market (the Parer Review), 20 December 2002.

276 Energy Reform: The way forward for Australia, A report to the Council of Australian Governments by the Energy Reform Implementation Group, 12 January 2007.

which the Rules may be improved to deliver greater efficiencies with respect to connection outcomes.

8.3.4 The Victorian connections regime

Issues specific to the Victorian connections regime were raised primarily by the NGF in its submission, which aimed to reflect the experiences of generators operating in Victoria.[277] Three key concerns were raised relating to:

- tripartite contractual arrangements;
- third party liabilities; and
- the imposition of additional obligations on generators in the construction of terminal stations.

Tripartite contractual arrangements and third party liabilities

The complexity of the tripartite contractual arrangements was raised both because of the additional transaction costs incurred by generators and load seeking to connect to the transmission network, and the limited scope for generators and load to influence the content and directions of negotiations. In particular, tripartite contractual arrangements are perceived to add complexity to the connection arrangements, thereby increasing the costs associated with obtaining a connection in Victoria.

In Victoria, the responsibilities for connections are split between AEMO and the transmission owner. In summary:

- a connecting party is required to enter into a connection agreement with the transmission owner in relation to the provision of connection services; and
- a connecting party is also required to enter into a connection agreement with AEMO (commonly called a Use of System Agreement) for the provision of shared transmission services.

Use of System Agreements may also require the connection party to impose technical conditions required by AEMO on the transmission owner.

If an augmentation to the shared network is required to facilitate the connection:

- AEMO will procure the construction of the augmentation and the provision of the network services using the augmentation pursuant to agreements with the transmission owner; and
- AEMO and the connecting party will enter into agreements for AEMO to on-provide those services in relation to the augmentation to the connecting party

277 See: NGF, Issues Paper submission, pp. 15-19.

and for the connecting party to underwrite AEMO's costs of procuring those services.

It was suggested that connection applicants at times consider that they are kept at an 'arms length' from negotiations, with limited opportunities to review and comment on draft documents. According to the NGF, this significantly hampers generators' ability to effectively negotiate cost and risk outcomes, while remaining liable for the services delivered under the contract.

This tripartite contractual arrangement also exposes AEMO to the liabilities incurred under the contacts. This leads AEMO generally to require that connection applicants provide bank guarantees to secure performance of their obligations. The NGF noted that, in other jurisdictions of the NEM, parent company guarantees are sufficient to cover the TNSP's exposure in the event that generators default. The NGF considered that the imposition of bank guarantees incurs an additional, inefficient cost for the connection process.

Construction and operation of parts of the transmission system

The NGF also raised concern regarding AEMO's requirements for generators that elect to construct and operate a terminal station that is part of the shared network. While a generator in Victoria is able to undertake such an activity, in the experience of generators in that state, AEMO requires "a number of additional protections in its connection documents over and above what it would normally if SP AusNet were to construct and operate the terminal station".

Further, Victorian legislative requirements place some restrictions on owning and operating both generation and network assets. In the view of the NGF, these arrangements and obligations make the possibility of constructing and owning an asset associated with the shared network "unviable".

Commission's current view

The Commission considers that the connection arrangements in Victoria should be further investigated under the connections workstream of the review, with a view to assessing whether they would benefit from specific refinements under the Rules to ensure their efficient operation.

The Commission also notes that AEMO, in collaboration with industry participants in Victoria, will this year pursue its own assessment of the current arrangements, with a view to identifying improvements to the connection process. The Commission will consider the outcomes of the working group in its consideration of Victorian connection issues under this review.

Abbreviations

AEMA	Australian Energy Market Agreement
AEMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Alinta	Alinta Energy
APR	Annual Planning Report
CEC	Clean Energy Council
CMR	Congestion Management Review
COAG	Council of Australian Governments
CPRS	Carbon Pollution Reduction Scheme
CRNP	Cost Reflective Network Pricing
DPI	Department of Primary Industries of Victoria
DSP	Demand-Side Participation
ENA	Energy Networks Association
ERIG	Energy Reform Implementation Group
ESOO	Electricity Statement of Opportunities
EUAA	Energy Users Association of Australia
FTR	Financial Transmission Right
IES	Intelligent Energy Systems
Infigen	Infigen Energy
International Power	International Power Australia
LRPP	Last Resort Planning Power
LYMMCo	Loy Yang Marketing Management Company

MCE	Ministerial Council on Energy
MEU	Major Energy Users
MNSP	Market Network Service Provider
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NEO	National Electricity Objective
NER	See Rules
NGF	National Generators Forum
NSCAS	Network Support and Control Ancilliary Services
NSP	Network Service Provider
NTFP	National Transmission Flow Path
NTNDP	National Transmission Network Development Plan
NTP	National Transmission Planner
RET	Renewable Energy Target
RIT-T	Regulatory Investment Test for Transmission
ROAM	ROAM Consulting
ROC	Rate of Change
RRN	Regional Reference Node
RRP	Regional Reference Price
Rules	National Electricity Rules
SENE	Scale Efficient Network Extension
SRMC	Short Run Marginal Cost
STPIS	Service Target Performance Incentive Scheme
TEC	Total Environment Centre

TNSP	Transmission Network Service Provider
TUoS	Transmission Use of System

A What is congestion and how is it measured?

This appendix provides additional details on how congestion may be defined and measured. It also provides a summary of previous studies that have attempted to measure the economic and efficiency impacts of congestion on the NEM.

A.1 What is congestion?

Transmission networks are physically limited in the amount of electricity they are able to transport. Congestion occurs when the flow of electricity reaches the physical limit of the affected part of the transmission network. Whenever a particular element on the network (e.g. a line or transformer) reaches its transfer limit and cannot carry any more electricity than it is carrying already, it is 'congested'. Such limits are usually expressed in the form of either 'thermal' or 'stability' limits:

- *Thermal limits* refer to the heating of transmission lines as more power is sent across them. The additional heat causes the lines to sag closer to the ground. The clearance above ground level must exceed certain minimum heights to ensure both public safety and power system security. Thermal limits also apply to other elements of the network, such as transformers.

- *Stability limits* refer to the need to keep the transmission system operating within design tolerances for voltage, with the ability to recover from disturbances, taking into account interaction control systems and other technical characteristics that are important to keep the power system intact. Stability limits tend to vary with the location and quantity of generation and demand, as well as with other factors.

Congestion occurs when these transfer limits are breached on particular transmission lines or network elements. To ensure power flows remain within transfer limits the market operator, AEMO, re-dispatches generators out of their normal merit order to meet demand.

Breach of these transfer limits, or congestion, is usually a function of a range of interacting factors, such as a particular pattern of energy flows, network deratings and forced or planned outages of either network elements or generators. These variables can change rapidly, which means that congestion might emerge and disappear between one five minute dispatch interval and the next.

The unpredictability of congestion arises in part from the fact that electricity splits and moves across many parallel paths in transmission networks. This means that power flows between two nodes can and will impact line loadings quite some distance away from the primary path, and can therefore cause congestion on these paths.

The implication of this is that it is generally difficult to ascribe the causes of congestion to particular parties.

A.2 Economic assessment framework

In undertaking any aspect of its role and functions the Commission is required to have regard to the NEO. Efficiency lies at the core of the NEO and, in particular, the AEMC must have regard to three forms of efficiency:

- *Productive efficiency* - outputs are produced at least cost, minimising the use of scarce resources. Market prices should reflect the least cost combination of inputs;

- *Allocative efficiency* - outputs are distributed in a Pareto optimal manner such that they are allocated to their most valued uses (no-one can be made better off without making someone else worse off). This usually requires that prices reflect costs at the margin (so appropriate trade-offs between consumption possibilities can be made);

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

The primary effect of congestion is that it changes the merit order of dispatch, 'constraining-off'[278] some generators and/or 'constraining-on'[279] others to ensure demand can continue to be met within secure transmission limits.

The effect of being constrained-on or -off and the consequential behavioural responses this elicits, impacts the productive, allocative and dynamic efficiency of the NEM. How these impacts should be considered from a conceptual perspective is discussed briefly below.

A.2.1 Productive efficiency

Congestion reduces productive efficiency by preventing demand from being met by the lowest cost combination of generation offers. When a constraint binds it may not be possible to dispatch all of the lowest cost generation offers available to meet demand, because their dispatch will cause transfer limits to be breached. Consequently, generator offers from unconstrained parts of the network will be dispatched instead, which increases the overall cost of meeting demand.

The effects of congestion on productive efficiency may be further reinforced by so called 'disorderly bidding' of generators in response to constraints. Under the NEM’s regional market design the offers of generators who are constrained-off (or on) are not taken into account in the price setting process. This means these generators can price

278 A generator is said to be 'constrained-off' when it is dispatched for a quantity *less* than the amount it desired to produce at the market price (the market price is above the generator’s offer price or SRMC).

279 A generator is said to be 'constrained-on' when it is dispatched for a quantity *greater* than the amount it desired to produce at the market price (the market price is lower than the generator’s offer price or SRMC).

their offers in non-cost reflective ways, recognising that this will not impact the actual price they are likely to receive for their dispatched energy.

Typically, generators that anticipate being constrained-off will price their offers at the price floor in order to maximise their opportunity for dispatch. The NEM Dispatch Engine (NEMDE)[280] is unable to distinguish high cost generators (such as peaking units) from low cost generators (such as base-load coal units) under these circumstances, as it simply observes the price floor offers from a range of generators affected by the constraint. Where all constrained generators price their offers at the price floor, dispatch is pro-rated amongst those generators, based on available capacity.

A.2.2 Allocative efficiency

Congestion also impacts allocative efficiency. It can do so firstly in terms of its impact on competitive generation offers. Constraints have the effect of creating sub-regional markets which can limit the degree to which generators can compete to set price (since generators which are constrained-off cannot set price). Congestion may therefore cause market prices to diverge from underlying resource costs. To the extent this lowers consumption below levels that would occur with more cost reflective pricing in place this reduces allocative efficiency (assuming that consumption is valued by consumers). This reduction in consumption and production is referred to as a dead weight loss, because the benefits of consumption exceed the costs of production, but these consumption possibilities are not realised. Consumers are worse off as a result.

Another way congestion can impact allocative efficiency is through its unpredictable impacts on generator cash-flows, which increases the risks of operating in the NEM. Where such 'congestion risk' becomes material it may increase contract premiums, as generators will seek to recover these risks through the contract market. Because most energy is supplied through contracts, higher contract prices may also contribute to lower than efficient levels of production and consumption, thereby reducing allocative efficiency.

For these reasons, the impacts of congestion on both generator competition and dispatch risk can reduce allocative efficiency.

A.2.3 Dynamic efficiency

Congestion may also reduce the dynamic efficiency of the NEM. This would occur, for example, if congestion reduces incentives to invest in new generation capacity or if congestion risk leads to less efficient market structures evolving over time (i.e., through excessive vertical integration to manage such risk).

Incentives to undertake significant capital investment will depend on the ability of investors to forecast cash-flows within a reasonable range; if congestion increases

280 The function of NEMDE is to optimise the dispatch of generators, using industry-standard linear programming tools.

uncertainty over cash-flows this may diminish both the capability and incentive for participants to invest in new generation capacity.

A further dynamic efficiency related consideration of congestion is the extent to which its costs are adequately captured and allocated in the market. For example, if locational decisions by generators can significantly increase the costs of congestion over time, yet they do not face such costs, then future productive and allocative efficiency may be impacted. The degree to which locational decisions can therefore impact evolving or future congestion patterns is an important consideration for this review.

A.3 Assessing the materiality of congestion

Congestion can therefore affect the productive, allocative and dynamic efficiency of electricity markets.

Assessing the current and future materiality of congestion under existing market frameworks should therefore be an important objective in justifying any changes to these frameworks. However, quantifying the economic impacts of congestion is not a straightforward task. Establishing dynamic efficiency losses for example, requires establishing a counterfactual of how markets would have evolved under lower levels of congestion, or forecasting the quantum and incidence of congestion into the future.

Allocative efficiency losses are also complex to measure as this requires establishing a hypothetical counterfactual of how much energy end users would have consumed had prices been lower.

For these reasons perhaps, the focus to date has predominantly been on quantifying existing productive efficiency losses of congestion, since comparing changes in merit order dispatch under 'constrained' and 'unconstrained' scenarios would appear to be relatively straightforward given current modelling tools. However, as we noted in the CMR,[281] even this approach, which is used by the AER, may be limited in what it can tell us about actual productive efficiency losses of congestion.

We review the current approaches for measuring the costs of congestion below and identify where improvements may need to be made in order for us the better assess the actual economic materiality of congestion.

A.3.1 Evidence of productive efficiency losses

In its annual reports on the State of the Energy Market, the AER published information and data for the years 2003/04 to 2008/09 on:[282]

- *Total Cost of Constraints* (TCC). The TCC attempts to measure the amount by which the cost of supplying load would fall if all transmission constraints were removed. It is calculated by comparing the dispatch costs arising from an actual

281 AEMC 2008, *Final Report*, Congestion Management Review, June 2008, Sydney, Appendix B.

282 AER, *State of the Energy Market*, 2009, pp. 140-143.

run of NEMDE versus one that removes all constraints for the same period; i.e. generators' offers and demand are assumed constant between the model runs.

- *Outage Cost of Constraints* (OCC). The OCC is similar to the TCC but only estimates the impact of removing all transmission outage constraints (but retaining other causes of congestion such as system normal constraints). This measure seeks to quantify the dispatch costs of congestion arising solely from network outages. It is calculated by running NEMDE with only "system normal" constraints and comparing the dispatch cost under that scenario with the actual dispatch cost.

- *Marginal Cost of Constraints* (MCC). The MCC estimates the amount by which the costs of supplying load would fall if the relevant transmission limit were increased by one megawatt. The key different between it and the TCC is that it focuses on the productive efficiency consequences of individual constraints, rather than constraints in aggregate.

All three measures assess the degree to which constraints prevent a lower cost dispatch. They determine the change in merit order dispatch between a constrained (reflecting actual market outcomes) scenario and an unconstrained scenario (reflecting a hypothetical counterfactual where constraints are removed). Offer curves and demand are assumed to stay the same for the purposes of the analysis. Congestion costs are then measured as the difference between dispatch outcomes under the two scenarios, multiplied by the sum of generator offers that constitute the supply curve in each scenario (this reflects the important assumption that offers reflect SRMC).

An important limitation of these approaches is that offer curves are assumed to reflect underlying resource costs, and this stays constant between scenario runs. This is unlikely to be the case however, as generator offers can be expected to diverge from costs under constrained conditions, for two reasons. First, because the offers of constrained generators are not taken into account in the price setting process, they will often price offers well below their SRMC to maximise their opportunity for dispatch (disorderly bidding). This incentive is removed when constraints are lifted. Second, those generators which remain unconstrained under the constrained scenario set price, and may bid above their resource costs in these circumstances, where competition is less effective. Once again, the capability and incentive of generators to behave in such a manner is much lower in the unconstrained scenario.

As a consequence, assessing congestion costs on the basis of generator offers will arguably not provide an accurate measure of productive efficiency losses associated with congestion, since offers will not reflect resources costs under constrained conditions.

Disorderly bidding

As part of the CMR, the AEMC commissioned Frontier Economics (Frontier) to undertake some modelling in order to better understand the extent to which disorderly bidding impacts productive efficiency.[283]

Frontier assessed the effects of disorderly bidding by comparing two scenarios in their modelling:

- A *base case* incorporating constraints where all plant is dispatched at their opportunity cost (e.g., all generators bid full capacity at SRMC). This is what would occur in a price-taking environment with no mis-pricing.

- A *disorderly bidding case* where plant which is expecting to be constrained has the freedom to bid or offer at market price cap or the market price floor, depending on whether they are constrained-on or -off respectively. This case assumes that generators can predict whether they are likely to be constrained-on or -off prior to submitting their final offer.

The difference between the two scenarios represented the additional costs of dispatching the market due to disorderly bidding. Frontier used estimates of actual variable costs (from ACIL Tasman data) rather than observed generator offers to represent resource costs, and subsequently observed the overall change in dispatch costs (multiplying old and new dispatch outcomes by ACIL Tasman's variable cost estimates and comparing the two) that resulted from allowing disorderly bidding.

It is important to note however, that the Frontier modelling assessed only the impacts of disorderly bidding rather than congestion *per se*, and therefore cannot strictly be compared to the AER approach. That is, Frontier did not model a 'without constraints' scenario; only behaviour in response to those constraints was measured. In other words, if generators were all nodally priced, and the incentive to bid non-cost reflectively is removed, then there would be no difference between the base case and the disorderly bidding case under the Frontier modelling. In both cases the response to the constraint would be the same: that is, generators would bid their resource cost.

A strength of the Frontier modelling is that it avoided the use of generator offers to measure productive efficiency changes, relying instead on estimates of actual variable costs provided by ACIL Tasman. Nonetheless, it provided an incomplete picture of the productive efficiency impacts of congestion. It focused on disorderly bidding but not the broader effects of congestion on increasing the costs of dispatch.

Mispricing

Mispricing occurs when network congestion causes a generator to be constrained on or off. It is measured by the difference between the market price (calculated at the RRN)

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[283] AEMC 2008, *Final Report*, Congestion Management Review, June 2008, Sydney, Appendix B, pp. 90-101.

and the 'shadow' nodal price calculated at connection point of a particular generator (effectively the marginal offer of that generator at this node).

In 2006, Dr Darryl Biggar developed a methodology for calculating the extent of mispricing in the NEM.[284] To calculate the nodal shadow prices for each connection point, Dr Biggar used data from the NEMDE. He then calculated the frequency, duration and magnitude of deviations between these nodal shadow prices and the RRP. In this way, his measure of mispricing indicates the extent to which different generators may be affected when constraints bind. In other words, where the RRP is above a generator's nodal shadow price (and not all of the generator's volume has been dispatched) the generator is assumed to be constrained-off, and if the RRP is below the generator's nodal shadow price (and the generator has been dispatched), then the generator is assumed to be constrained-on.

In its latest State of the Energy Market report, the AER reports on the extent of mispricing in the NEM, noting that while the number of connection points that are being mispriced has tended to stay steady over the last few years, the duration of mispricing has increased markedly in some areas and varies significantly between different parts of the NEM (for example, it is much higher in Queensland and in Victoria, compared to elsewhere).[285]

While such analysis of mispricing can provide some very useful information on the nature and frequency of intra-regional constraints, such analysis does not, nor does it purport to, assess the impacts of mispricing on efficiency.

A.3.2 Evidence of allocative and dynamic efficiency losses

Congestion impacts on spot prices

The allocative efficiency costs of congestion are measured by the extent to which the deviation of market (and/or contract) prices from underlying resource costs reduces overall consumption (and consequently production). The actual allocative efficiency costs of congestion have been little examined in the NEM to date.

Potential allocative efficiency losses of congestion have been identified by AEMO.[286] In its analysis of the Wallerawang constraint in New South Wales, AEMO found that substituting actual offers with offers more reflective of competitive supply conditions would have led to a market price of $90/MWh for the period between 10:30AM and 3:30PM on 7 December 2009, rather than the actual observed price of $4,917/MWh. They calculated that the $90/MWh price would have reduced customer settlement by approximately $300 million.

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284 Dr Biggar's report, *How significant is the mispricing impact of intra-regional congestion in the NEM?*, (25 October 2006) is available from the AEMC website.

285 AER, State of the Energy Market, 2010, p. 63.

286 AEMO, Issues Paper submission, Appendix B.

However, it is important to note that this value is not strictly a loss in allocative efficiency, but rather represents a wealth transfer from consumers to producers. To quantify these losses in allocative efficiency terms would require an assessment of how the $90/MWh price would affect demand. The increase (decrease) in demand multiplied by the lower (higher) price would represent the measure of the allocative efficiency gain (loss) achieved by removing a particular constraint (which depends on the elasticity of demand).

Moreover, given the level of contracting typical in the NEM, the wealth transfer is not necessarily all in one direction, with transfers between generators and from generators to retailers also highly likely. The elasticity of demand in the particular circumstance outlined by AEMO would be expected to be low (many retailers would have been hedged to high pool prices in New South Wales).

It is also important to arrive at a robust determination of what the competitive benchmark price might look like in the absence of congestion. AEMO used generator offers from unconstrained time periods to represent competitive costs. However these offers may differ due to a range of factors other than the level of competition (since the market conditions are different at different time periods).

A more robust approach might be to model how generators might actually respond (using game theory, for example) to the removal of a constraint, assuming market conditions remain the same. This type of analysis is used to assess competition benefits associated with expanding transmission capacity under the RIT-T. However, the Commission understands competition benefits have not been assessed in relation to transmission projects to date.

The Commission considers the RIT-T, particularly its competition benefits methodology using game theory, could provide a useful conceptual framework for assessing both the productive and allocative efficiency costs of congestion.

Congestion impacts on risk

Another indicator of the potential allocative efficiency losses of congestion is the extent to which congestion increases the risks of operating in the NEM. Higher risks are likely to be reflected in higher contract premiums and, given that most electricity is supplied under contracts, a divergence of contract prices from underlying resource costs may indicate a loss in allocative efficiency.

Higher market risks may also reduce the liquidity of contract markets and create a barrier to entry for smaller non-vertically integrated players who rely on such contracts to operate effectively in the market. Thus material congestion risk may also have dynamic efficiency implications for the efficient evolution of market structure.

Assessing contract market liquidity and pricing (including the market for SRAs), combined with participant surveys, can provide broad indications of the extent to which congestion is seen as a material problem in the market and whether existing tools are capable of managing it. This type of analysis was undertaken previously for the CMR.[287] The Commission will consider in what ways this analysis might usefully be extended to inform the current review.

In its submission to the Issues Paper, AEMO provided some evidence on the recent historical effectiveness of SRAs.[288] It assessed the degree to which SRAs have provided an effective hedge for price differences across interconnectors over the last few years and showed that such instruments still perform poorly at certain times, often when they should be most valuable. AEMO suggested that this may be significantly due to the effects of disorderly bidding. The Commission intends to consider this issue further.

A.4 Assessing the materiality of future congestion

The above analysis has focussed on measuring the materiality of existing congestion in the NEM. However, an important issue highlighted in the CMR, and examined in greater detail by the AEMC in the *Review of Energy Market Frameworks in light of Climate Change Policies*,[289] is the likely effects on congestion of climate change policies.

A key concern identified in the *Review of Energy Market Frameworks in light of Climate Change Policies* was that a lack of locational signals (for example, due to inadequate pricing of intra-regional congestion and/or the absence of a generator transmission charge) could lead to high volumes of new renewable generation locating in remote or already congested parts of the network, increasing congestion costs. As part of that review the AEMC commissioned modelling by both Intelligent Energy Systems (IES) and ROAM Consulting (ROAM) to analyse this issue. Potential congestion was examined under three different sets of transmission arrangements out to 2020, assuming an expanded RET and carbon price set to achieve a 5 and 15 per cent emissions reduction target:

- *Scenario 1*: non-responsive transmission – generators make profit maximizing decisions under the knowledge that transmission capacity is only developed where it is essential for ensuring demand is met.
- *Scenario 2*: existing arrangements working effectively – generators enter on the assumption that any intra-regional and inter-regional transmission constraints will be addressed using the RIT-T. The key difference in this scenario is that transmission developments which are considered to have net market benefits are built, whereas in scenario 1 they are not.
- *Scenario 3*: co-optimising central planner – generation and transmission is co-optimised to ensure demand growth is met at minimum cost.

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287 AEMC 2008, *Final Report*, Congestion Management Review, June 2008, Sydney, Appendix B.

288 AEMO, Issues Paper submission, Appendix A.

289 AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, Sydney.

The first scenario was intended to measure how generators would locate if transmission investment was expected to be minimal. This would require generators to weigh more explicitly, compared with current arrangements, the level of network access against the benefits of locating in particular areas (for example to be near an attractive fuel resource). This is because TNSPs would be unlikely to expand transmission by regulated means to accommodate connections in areas of scarce transmission capacity.

Under the second scenario, which was intended to reflect existing arrangements, participants would invest assuming that transmission would only be expanded if the market benefit of doing so exceeded the costs.

The third scenario attempted to establish the most efficient combination of transmission and generation development to meet demand out to 2020, ensuring climate change polices are met and the overall combined costs of generation and transmission is minimised while doing so.

Differences in overall system costs between the three sets of market arrangements were then calculated. While there were some differences in approach and assumptions between ROAM and IES (for example ROAM focussed on interconnector augmentations only, while IES attempted to capture some of the intra-regional transmission costs), both consultants found little demonstrable difference in overall costs between scenarios.

However, there are a number of important qualifications to this analysis. First, only system normal conditions were modelled (outages were ignored) and transmission was built to meet a 50 per cent probably of exceedance. Both assumptions are likely to substantially underestimate the costs of congestion and associated transmission costs.

Second, a relatively narrow range of transmission developments were considered, and transmission cost estimates used were considered highly uncertain, due to the limited time available to reliably vet these estimates.

Third, generators were assumed to bid at SRMC under both sets of analyses. However, as discussed above, congestion under the existing market design causes generators to bid in non-cost reflective ways, which may significantly increase the impacts of congestion.

For these reasons, the Commission is considering whether to revisit this analysis and update it for the present review.

A.5 Possible areas for future analysis

The discussion in the previous sections demonstrate that while a number of useful studies have been undertaken in examining the current and future materiality of congestion in the NEM, these studies are subject to significant limitations and are therefore also limited in the conclusions that may be drawn from them.

Perhaps the most complex area of investigation in this review is how to assess likely future congestion on networks. Modelling congestion patterns more than a few years out is an extremely complex exercise. It requires the prediction of future generator decisions as well as that of TNSPs in responding to these decisions under existing and/or forecast network regulatory arrangements.

The Commission would welcome views from participants on:

- how the productive efficiency losses of congestion can be measured;
- the extent to which allocative efficiency costs of congestion, both in terms of its competition and risk dimensions, might be robustly assessed; and
- how future materiality of congestion could be better assessed.