REVIEW

Australian Energy Market Commission

ISSUES PAPER

Transmission Frameworks Review

Commissioners

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Issues Paper

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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 to be the rule maker for national energy markets. The AEMC is currently responsible for rules and providing advice to the MCE on matters relevant to the national energy markets. We are an independent, national body. Our key responsibilities are to consider rule change proposals, conduct energy market reviews and provide policy advice to the Ministerial Council as requested, or on AEMC initiative.

Executive summary

The National Electricity Market (NEM) is currently facing its most significant period of change since its implementation in 1998.

Substantial new investment in all stages of the supply chain for electricity services is required over the next decade in order to maintain secure and reliable electricity supplies. Policies including the expanded Renewable Energy Target (RET) and proposals for a direct or indirect price on carbon are expected to drive significant new investment in renewable and low carbon generation. Additionally, extreme weather events may affect operating conditions for networks.

These factors could lead to changes in patterns of generation and network flows, with much of the new generation potentially located in areas remote from load centres and the existing transmission network. These changes are in turn expected to drive the need for significant levels of new transmission investment.

Transmission frameworks will need to be responsive

Transmission frameworks are the regulatory and market arrangements that govern investment in, and the funding, pricing and operation of, transmission networks.

While the existing transmission frameworks have delivered investment in network infrastructure, it will be important to ensure that they are sufficiently responsive to the challenges posed by changing patterns of generation and demand side participation in the market.

With the potential requirement for significant network investment in the future, Transmission Network Service Providers (TNSPs) will need to react appropriately to the needs of the market. Investment in transmission will need to occur in a timely manner and at locations on the network where it is needed.

Robust transmission frameworks with appropriate incentives on TNSPs should help to minimise future risks of uneconomic levels of network congestion. This is critical to provide generation businesses with sufficient certainty to invest in generation assets, as well as delivering security of supply and reliability at least cost to consumers.

In response to these challenges, the Ministerial Council on Energy (MCE) has directed the Australian Energy Market Commission (AEMC or 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.

This document commences the Commission's review of transmission frameworks and sets out for consultation the key issues for consideration in the review, in light of the Terms of Reference issued by the MCE.

Challenges to existing transmission frameworks

The competitive wholesale market in the NEM is reliant on both efficient network investment and efficient network operation by TNSPs. To the extent that deficiencies exist in the frameworks governing network investment and operation, these have the potential to impose significant costs on consumers through higher prices and risks to security of supply and reliability. These costs could be exacerbated given the challenges posed by climate change policies and the changing market landscape.

In this document we discuss the existing frameworks for both network investment and network operation and set out the challenges which underpin the need for this review.

Risks of inefficient transmission investment

Different and uncertain patterns of flows across the network and substantial new generation investment away from traditional locations could increase the risks that TNSPs will under-invest in certain areas and over-invest in others. If transmission is not built in a timely manner or is built in the wrong areas (as a result of inaccurate forecasts), this may lead to increasing levels of congestion on the network and reduced reliability of network services.

While some level of congestion is likely to be efficient, excessive congestion may result in higher costs to customers to the extent that efficient generation is unable to access the NEM. Similarly, if network investments are undertaken which ultimately prove unnecessary, this may also lead to assets being stranded and higher prices for customers.

The current services provided by TNSPs are primarily driven by customer reliability standards. This review will assess the extent to which TNSPs have obligations or incentives in relation to individual load customers, and the incentives on TNSPs to invest in response to changes in the location of generation. While important changes have been made to planning frameworks, it will be necessary to consider whether these are sufficiently resilient to the challenges posed by an uncertain and changing market landscape and provide appropriate incentives on TNSPs.

Generation investment uncertainty and congestion

Insufficient or delayed investment can lead to congestion on the network. Congestion creates significant uncertainties over access to the network and may undermine investment and commercial planning decisions in the generation sector, particularly in the current environment where access to financing for generation is likely to be constrained. This could impact on security of supply and reliability, as well as leading to higher prices for consumers.

The levels of congestion will be driven in part by the location and level of network investment. Congestion can be reduced through TNSPs maximising the network capacity available at times when it is most important to the market. It will therefore be important for this review to consider the incentive arrangements underpinning network availability.

Risks of inefficient locational decisions

There are a range of factors that impact on the locational decisions made by generators, including access to fuel sources, the risk of constraints and the costs of transmission losses. However, under the existing frameworks there is no price-based incentive on generators to locate new generation plant at points on the network that take account of the costs of investment in the shared transmission network driven by the locational decision. This is because generators are not exposed to the costs of investment in the shared network through existing pricing frameworks.

This lack of signals could result in inefficient investment in the shared transmission network leading to unnecessary costs being passed onto consumers in the form of higher prices. Consequently, in this review, we intend to assess the extent to which potential changes to the pricing of transmission might lead to materially more efficient outcomes.

A long term vision for the role of transmission

In conducting this review, the Commission intends to propose a long term vision for the appropriate role of transmission in providing services to the competitive sectors of the market, including both generation and load customers.

In an efficient market, total system costs across the whole supply chain are minimised. This does not mean that transmission investment should be minimised in isolation, but rather that investment in transmission and in other parts of the supply chain, in particular generation, should be optimised in combination.

The role of transmission therefore needs to be specified in a way that facilitates this minimisation of total system costs. Detailed arrangements for transmission investment, funding, pricing and operation can then be informed by this settled role.

Reaching a common view as to the appropriate role of transmission will involve considering the nature of the services currently provided by TNSPs to generators and load, and determining whether the services provided by TNSPs are defined clearly enough such that TNSPs are sufficiently accountable for investment and operational decisions. Similarly, the review will consider the framework under which generators and large loads make investment and operational decisions and the extent to which these are influenced by the services provided by TNSPs and the costs associated with these services.

The development of this vision will be based on a holistic assessment of the existing frameworks to determine whether any inefficiencies or weaknesses are present. This assessment will be undertaken having regard to the National Electricity Objective (NEO) as well as the objective for transmission frameworks of minimising total system costs, as set out above.

The Commission's assessment will be informed by any evidence provided by respondents on the extent to which there are any deficiencies associated with current service provision by TNSPs. To the extent that material deficiencies are identified, the Commission will consider, in line with the MCE's Terms of Reference, whether reforms are required to better align the incentives of network and generation businesses.

Transmission frameworks are complex and inter-related

There are important interactions between the core elements of the frameworks for transmission planning, the regulation of network investment and operation, and network pricing and access. In addition, different elements of the framework are subject to their own institutional governance arrangements. Therefore, if the Commission concludes that changes to the frameworks are required, then the inter-relationships between various elements of the transmission frameworks means that it is likely to be necessary to develop internally-consistent "packages" of reforms.

However, the Commission also recognises that regulatory certainty has value in itself to those making investment or operational decisions as a generator or on the demand side of the market. Before making any recommendations for change, the Commission will therefore require evidence that any deficiencies associated with current frameworks are or are likely to be significant enough to materially affect the achievement of the NEO.

Any potential reforms recommended by the Commission will also need to be planned on a long term basis with a view to ensuring that a stable framework is provided to promote overall efficiency and a more certain investment climate for generation and load. Such changes should aim to ensure that transmission frameworks are sufficiently flexible and capable of responding to change in a period of significant uncertainty.

List of questions for submissions to address

The Commission intends this to be a broad ranging review of transmission frameworks and would welcome the views of interested parties in relation to any of the matters discussed in this document. However, to help focus responses, we have set out a number of specific questions in each chapter. These are replicated below.

In particular, we are requesting stakeholder views as to:

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

In commenting on the materiality of each issue, respondents are requested to present relevant evidence or describe pertinent experiences with existing transmission frameworks, highlighting how these demonstrate that the frameworks may not be consistent with the achievement of the NEO or the objective for transmission frameworks of minimising total system costs, as set out in this paper.

Chapter 3: Determining the appropriate role of transmission

Question 1 Application of the NEO

Do frameworks governing electricity transmission allow for the minimisation of total system costs and for overall efficient outcomes in accordance with the NEO? What evidence, if any, is there to demonstrate that this is or is not the case?

Question 2 The role of transmission

Is there a need to consider the appropriate future role of transmission in providing services to the competitive sectors of the NEM? What evidence, if any, is there to suggest that the existing service provided to facilitate the market, or the definition of this service, is inappropriate or insufficient?

Chapter 4: Key issues for efficient investment

Question 3 Transmission planning

Does the current transmission planning framework appropriately reflect the needs and intention of the market (including generators, loads and demand side response)? Will this adequately provide reliable information to TNSPs on where and when to invest, or when to defer or avoid investment, in an uncertain planning environment, or is there a case that additional market-based signals might be beneficial?

Question 4 Promoting efficient transmission investment

Will existing frameworks, including the recently introduced RIT-T, provide for efficient and timely investment in the shared transmission network?

Question 5 Economic regulation of TNSPs

Does the current regime for the economic regulation of transmission lead to efficient network investment? Do the incentives on TNSPs lead to appropriate investment decisions and the efficient delivery of additional network capacity?

Question 6 Network charging for generation and loads

Is a price signal of locational network costs for generators required to promote overall market efficiency? Would there be any consequential impacts on transmission pricing arrangements for load?

Question 7 Nature of access

Would it be appropriate for generators and load to have the option of obtaining an enhanced level of transmission service? Would this help generators to manage risks around constraints and dispatch uncertainty?

Question 8 Connection arrangements

Do current arrangements for the connection of generators and large end-users reflect the needs of the market? To the extent that more fundamental reforms to transmission frameworks are considered under the review, would it be appropriate to revisit the connection arrangements?

Chapter 5: Key issues for efficient operation

Question 9 Network operation

Are more fundamental reforms required to financial incentives on TNSPs to manage networks efficiently and to maximise operational network capability for the benefit of the market? Should further options for information release and transparency on network availability and outages be considered?

Question 10 Dispatch of the market and management of congestion

Is there a need for material congestion to be more efficiently managed in the NEM?

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1 The Review

1.1 Introduction

The National Electricity Market (NEM) is undergoing a significant period of change. 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 to address climate change concerns are expected to drive significant new investment in renewable and low carbon generation. Extreme weather events may affect levels of demand and operating conditions for networks.

Renewable generation, in particular, is expected to locate in areas remote from load centres and the existing transmission system, requiring significant new investment in transmission in the long term. The changing patterns of generation and network flows may also increase the congestion present on the network in the short term.

While the existing transmission frameworks have delivered investment in network infrastructure, it will be important to ensure that they are able to respond to the challenges posed by these changes. If frameworks are not sufficiently responsive, a number of risks may eventuate.

One result might be over-investment in transmission, increasing end costs to consumers. Equally, under-investment might lead to increased congestion, with associated costs. This may also lead to generators facing uncertainty as to the service they will receive from transmission meaning that they might be less likely to invest, potentially leading to less reliable electricity supplies.

In response to these challenges, in April 2010 the Ministerial Council on Energy (MCE) directed the Australian Energy Market Commission (AEMC or 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 objective of the review is to ensure that incentives for transmission and generation investment and operation are aligned to promote efficient and reliable service delivery across the electricity supply chain.

The review stems from our previous Review of Energy Market Frameworks in light of Climate Change Policies (Climate Change Review or CCR). In the Final Report for that review (submitted to the MCE on 30 September 2009), we concluded that, although energy market frameworks for Australian gas and electricity markets are generally capable of accommodating the impacts of climate change policies efficiently and reliably, framework changes were required in certain areas. In particular, we indicated that additional work was required to develop and assess changes relating to the provision and use of the shared transmission network. This review provides the opportunity for the further consideration of these matters.

1.2 MCE direction

As noted, the MCE has directed the AEMC to conduct a review of electricity transmission frameworks in line with a Terms of Reference approved on 20 April 2010.

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. 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, and will allow for consideration of a wider range of issues than we had identified in the CCR Final Report. This is particularly important given the inter-related nature of the issues involved (for example, there is an interaction between the levels of investment in the transmission system and the costs of network congestion that result). A broad review will also allow for the consideration of issues that have been matters of concern and debate in the NEM for some time.[1]

The remainder of this Issues Paper therefore sets out for consultation the key issues we have identified for consideration in the review. It explicitly does not attempt to identify or assess possible solutions to these issues - this will form a later stage of the review process. The paper also provides information relating to how we intend to progress the review and the subsequent stages of consultation planned.

The full MCE direction is provided as Appendix A.

1.3 Recent related initiatives

As indicated above, a number of previous reviews and Rule changes have been undertaken in relation to arrangements for transmission. A summary of relevant

1 A summary of relevant initiatives is provided in Appendix B of this document.

reforms and reviews is provided in Appendix B. However, three of the most relevant recent and ongoing developments are highlighted below.

1.3.1 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 Council of Australian Governments (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 (with a full NTNDP to follow in December 2010). The arrangements for the RIT-T commenced operation on 1 August 2010.

1.3.2 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. The MCE is currently considering its response to this report.

1.3.3 Review of Demand-Side Participation in the NEM

On 20 July 2010, the MCE released its response to the Stage 2 Final Report of the AEMC's Review of Demand-Side Participation in the NEM (DSP Review).

As part of its response, the MCE endorsed the AEMC undertaking a Stage 3 of the DSP Review relating to issues associated with the introduction of smart grid and smart metering technology. The MCE requested that certain elements of COAG's National Strategy on Energy Efficiency (NSEE) be considered by the AEMC when developing the terms of reference for Stage 3 of the review.

We are currently considering the MCE response and terms of reference for Stage 3 of the review.

We 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.

1.4 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-
>
> (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 COAG in relation to the NTP and RIT-T. As outlined in the MCE direction, these principles are that:

- 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 to also 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.

1.5 Process

1.5.1 A comprehensive review

The Terms of Reference for the review recognise the complex and inter-related nature of transmission frameworks by requiring us to consider them in a holistic manner. This need to undertake a comprehensive review is reflected in the timetable for the review, which allows until 30 November 2011 for the submission of the final report.

Although we previously made recommendations in this area in the CCR Final Report, the broad scope of the Transmission Frameworks Review (TFR) will provide the opportunity to consider all potential solutions in an integrated fashion.

To this end, in later stages of the review we intend to develop and assess coherent, internally-consistent "packages" of framework options. The mutual incompatibility of many specific options, and the risk of unintended consequences, mean that partial approaches are unlikely to deliver optimal outcomes and that robust solutions cannot, therefore, be developed in isolation.

In assessing such policy packages, we will be mindful of likely trade-offs between the optimality of solutions and the practicality of their implementation. We intend only to make recommendations for change if we are satisfied that any deficiencies associated with current frameworks are or are likely to be significant enough to materially affect the achievement of the NEO.

1.5.2 The Review timetable

The table below sets out our indicative timetable for the review.

Document	Purpose	Date
Issues Paper	To present the key issues identified by the Commission and set out the process for the review.	**Submissions due 29 September 2010**
Options Paper	To conclude on the issues to be considered (in light of stakeholder submissions) and to identify and discuss the range of potential options to address these.	Late 2010
1st Interim Report	To identify and discuss a short list of potential internally-consistent policy "packages" and to explain the framework for the assessment of these.	Early 2011
Public Forum		During the consultation period for the 1st Interim Report

Document	Purpose	Date
2nd Interim Report	To assess the packages identified in the 1st Interim Report, and to make a draft recommendation in this respect.	Mid-2011
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 November 2011

1.5.3 The stakeholder engagement process

We are committed to undertaking this review in an open and transparent manner. Effective engagement with our stakeholders is essential to ensure that all issues are canvassed and addressed. Key parts of this will be the submissions to our consultation documents, bilateral discussions with stakeholders and public and industry forums. Information on consultation documents is provided above. We currently anticipate holding a public forum following publication of the 1st Interim Report.

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 Australian Energy Regulator (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, Environment 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	Rob Jackson, Deputy Director: Clean Energy Council
Australian Geothermal Energy Association	Terry Kallis, Chairman: Petratherm

Member Organisation	Representative
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
Major Energy Users	Shane Bewry, Chair: Major Energy Users
Total Environment Centre	Jane Castle, Senior Campaigner: Total Environment Centre

The first meeting of the Consultative Committee was held on 26 July 2010. Outcomes of the meeting can be found at www.aemc.gov.au.

How to make a submission

The closing date for submissions to this Issues Paper is 29 September 2010.

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 Issues Paper

The remainder of this Issues Paper is structured as follows:

- **Chapter 2** provides context regarding the challenges for transmission frameworks;
- **Chapter 3** discusses the inter-related nature of transmission frameworks and how we consider the appropriate role of transmission should be determined;

- **Chapter 4** considers the key issues related to ensuring that efficient investment decisions are made by transmission and generation; and

- **Chapter 5** considers the key issues related to efficient operational decisions for transmission and generation.

2 Challenges for transmission frameworks

2.1 Introduction

The purpose of this chapter is to describe the key challenges for transmission networks that have led to the review. The chapter discusses:

- the significant investment challenge for the NEM in the next decade, and its impact on transmission frameworks;
- the specific further impacts that climate change policies may have on the NEM, including a summary of the relevant recommendations that we have previously made in response to the introduction of these policies; and
- the potential impacts of extreme weather events.

2.2 The investment challenge and transmission frameworks

The NEM is currently facing a significant period of change. Substantial new investment in all stages of the electricity supply chain is required over the next decade in order to maintain secure and reliable electricity supplies.

The creation of the NEM occurred at a time when surplus capacity existed in the market, arising from the previously state-owned vertically integrated electricity suppliers. Over time this excess capacity has been absorbed. Further, some of the underlying infrastructure is relatively old.

There will therefore need to be investment to renew existing infrastructure and to provide such additional capacity as represents an economic response to meet continued population and economic growth in Australia.

In order to meet this growth, Australia's electricity generation is projected to grow by nearly 50 per cent in the period to 2030.[2] Forecasts suggest that up to $32 billion of investment in generation could be required by 2020.[3]

Large scale new entry (and exit) in generation to reflect changes in the relative profitability of different forms of generation is likely to place significant pressures on the ability of transmission businesses, individually and collectively, to respond efficiently. The arrangements governing the NEM should be designed such that there is an efficient response to any changed circumstances, whether demand is increasing or decreasing.

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2 Syed, A, Melanie, J, Thorpe, S and Penney, K 2010, *Australian energy projections to 2029-30*, ABARE research report 10.02, prepared for the Department of Resources, Energy and Tourism, Canberra, March 2010, p.30.

3 Simshauser, P. (2010), "Resource adequacy, capital adequacy and investment uncertainty in the Australian power market", *Electricity Journal*, 23(1): pp.67-84.

To the extent that the transmission response to changes in patterns of generation and levels of demand is inefficient, it is likely that costs to consumers will be unnecessarily high. Additionally, uncertainty in the level of the service that will be provided by transmission may impact on the amount of generation investment that is forthcoming, with any shortfalls in this area potentially affecting the reliability of supply. This is particularly important in the context of the current financial market, where access to finance may be more constrained - with many competing demands on what is available.

The service provided by transmission is governed by a range of national and jurisdictional legislation and instruments, including the Rules and subordinate guidelines, policies and procedures. In this document, we refer to these regulatory and market arrangements collectively as transmission frameworks. These frameworks set out the detailed arrangements for investment in, and the funding, pricing and operation of, transmission networks.

Significant reforms to the transmission frameworks, such as the establishment of the NTP function in AEMO, have already been enacted to help meet the challenges outlined above. However, in this review we aim to determine whether there is a need for further reform, particularly in response to current and likely future changes to policy settings to address climate change concerns. These policies are likely to exacerbate the challenges facing the transmission sector, and the specific impacts of these are discussed in the next section.

2.3 Impacts of climate change policies on energy markets

The investment task discussed above is magnified by a desired shift to less carbon-intensive generation. Commonwealth and jurisdictional governments have implemented a number of policies to address climate change concerns, and have proposed further measures. The section explores the impacts that such policies may have on the NEM.

As discussed below, we have already examined the possible impacts of the expanded Renewable Energy Target (RET). We note the Australian Government's recent decision to delay the implementation of the Carbon Pollution Reduction Scheme (CPRS), but also the possibility of the introduction of a carbon pricing mechanism in the future.

2.3.1 Climate change policies will impact on behaviour and investment

The expanded RET and other policy initiatives directed at carbon reduction, including various proposals for a direct or indirect price on carbon, are intended to have direct effects on behaviour and investment in Australia's energy markets. This is because electricity generation is currently highly carbon-intensive, with coal-fired generation accounting for around 85% of generation output in the NEM.[4]

4 AER 2009, *State of the Energy Market 2009*, p.55.

Broadly, these policies and proposals aim to change the underlying economics of generation, by encouraging investment in new plant with lower carbon intensity than the bulk of the existing generation fleet. This would have the effect of altering the dispatch, and therefore utilisation, of existing generators.[5]

The expanded RET is intended in particular to bring forward investment in renewable energy. This renewable generation capacity appears likely to be dominated by wind-powered generation due to its initial cost advantage relative to other available renewable technologies.[6] Such an outcome would, in turn, trigger investment in new, flexible, "peaking" gas-fired generation to complement the intermittent nature of windfarm output (i.e. to provide capacity to back-up the wind-powered generation at times when it is not running).[7]

The effects of the entry of significant amounts of wind-powered generation will be exacerbated if, as has been suggested, it is clustered in specific geographical areas and often remote from the grid and load centres.[8] The result for transmission networks will be an increase in remote connection applications and an increased requirement for investment in the shared network. The latter will be driven by different patterns of generation and network flows, due both to new generation entry and to consequential changes to the dispatch of existing plant.

However, there is significant uncertainty in the long term about the type and location of the large amount of generation investment that is required, including new baseload plant. Transmission frameworks will therefore need to accommodate a broad range of potential outcomes.

2.3.2 Recommendations made in the Review of Energy Market Frameworks in light of Climate Change Policies

We have previously examined the impacts of climate change policies across all Australian gas and electricity markets. We concluded that energy market frameworks, supported by a number of recommended changes, are capable of accommodating the impacts of the expanded RET and the potential CPRS.[9] The changes recommended seek to improve and strengthen the ability of the energy markets to respond to the climate change policies while continuing to meet the desired market outcomes of efficient and reliable energy services.

We concluded that changes to network flows arising from changing patterns of generation would create pressures for network investment in the long term and to increase the prevalence of network congestion arising in the short term. A number of

5 AEMC 2008, *Survey of Evidence on the Implications of Climate Change Policies for Energy Markets*, December 2008, Sydney, pp.38-41.

6 Ibid, p.33.

7 Ibid, p.43.

8 Ibid, pp.70-71.

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

recommended changes were therefore proposed in respect of the shared transmission network. These were targeted at inefficiencies identified in respect of generator incentives to make efficient location and retirement decisions, and to offer their output at prices that reflect their operating costs. These recommendations were that:

- A transmission charge should be introduced to signal to generators differences in costs associated with connection to, and use of, the network, in particular the extent to which the 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.
- 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 has led to the initiation of this review.

We also recommended two other framework changes of potential relevance to this review:

- The introduction of a new framework for the efficient connection of clusters of new generation that are expected to seek to connect in the same location over a period of time. The purpose of the proposed **Scale Efficient Network Extensions** (SENEs) would be to allow the connection of multiple generators to transmission (or distribution) networks so as to prevent the inefficient duplication of connection assets that might otherwise occur.
- The introduction of an obligation on transmission businesses to levy **inter-regional transmission charges** on transmission businesses in adjacent NEM regions. This proposal seeks to improve the cost-reflectivity of transmission charges and the allocation of costs across regions. The existing implicit cross-subsidies between customers in different regions could represent a potential barrier to the co-ordinated planning of transmission investment across regions.

On 15 May 2010, the MCE submitted requests to change the Rules to progress both of these proposals. The Commission began the consultation process for the SENEs Rule change proposal on 1 April 2010, and a Consultation Document was published to provide guidance to stakeholders in this regard.[10] The Commission began the consultation process for the inter-regional transmission charging Rule change on 13 May 2010, and a Consultation Document was similarly published.[11]

In undertaking the review, we will take account of the progress of these initiatives.

10 AEMC 2010, *Scale Efficient Network Extensions*, Consultation Paper, 1 April 2010, Sydney.

11 AEMC 2010, *Inter-regional Transmission Charging*, Consultation Paper, 13 May 2010, Sydney.

2.4 Potential impacts of extreme weather events

The MCE direction requires us to review transmission frameworks in light of the potential impacts of extreme weather events.

We consider that four types of extreme weather may have effects on the security and reliability of electricity supply: heat waves, droughts, storms and floods. The following sections discuss each of these in turn.

2.4.1 Heat waves

A heat wave is a period of abnormally hot weather lasting several days.[12] A consequence of heat wave conditions for the NEM can be very high electricity demand for extended periods. In some cases, peak demand can reach record levels. High peak demand is often observed in regions where a large proportion of the population relies on electric air-conditioning units.

The exact effect of heat waves is dependent on the shape of the demand profile. Where demand spikes are higher than usual but not necessarily longer, more generation can be required, albeit only to run for very short periods, to satisfy the higher demand peak. However, where the frequency or duration of demand spikes increases, it may be possible for existing generators to run for longer to meet this demand, and additional investment may not be required.

Heat waves may also decrease the ability of the combined electricity system to meet demand. The principal effect on generating plant is a restricted ability to produce rated output. There are a number of reasons for this, including: reduced thermal capacity; limited access to cooling water; increased risk of plant failure; technical limitations; and increased unplanned maintenance.

Heat waves and bushfires can adversely affect the capability of a transmission network to transport electricity to load centres by forcing transmission lines to reach their thermal limits or by arcing. Heat waves and bushfires can also disrupt the ability of distribution networks to supply electricity.[13]

2.4.2 Droughts

Droughts can have serious consequences for generation availability. Some thermal generators may require fresh water to cool generating units. Where there is insufficient water available for cooling, the output of the generating unit is necessarily constrained.

Droughts also impact on the ability of hydro generators to generate electricity. Clearly, the absence of sufficient water reserves will have a direct and practical impact on whether a hydro generating unit is physically able to generate electricity. However,

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12 Bureau of Meteorology, www.bom.gov.au/lam/glossary/hpagegl.shtml

13 For information on issues relating to distribution networks and the 7 February 2009 bushfires in Victoria, see: 2009 Victorian Bushfires Royal Commission, *Final Report*, 31 July 2010.

limited water supply will also increase the opportunity cost of producing electricity. Hydro generators may therefore face changed incentives in deciding what price and level of capacity, if any, they will offer into the market.

These effects may lead to changes in the pattern of generation and, consequentially, to the levels of congestion on the transmission system.

2.4.3 Storms and floods

The main potential impacts of storms and flooding are direct damage to elements of electricity networks. Lightning strikes during storms can cause arcing between transmission lines in a similar way to bushfires. The built-in protection systems will activate to trip the endangered lines.

Floods and high winds during storm periods and cyclones may also mobilise debris. This debris can damage transmission elements, such as wires and substations, causing supply interruptions. These effects are less severe than for distribution networks, however, which have a lower minimum ground clearance and which are therefore more susceptible to damage or interruption due to falling trees and debris during storms and floods.

These effects may impact on TNSPs' maintenance and operational requirements. They may also reduce the capability of the network to transport electricity, and this may additionally lead to an increased level of congestion.

3 Determining the appropriate role of transmission

The Transmission Frameworks Review will comprehensively assess transmission frameworks in the NEM. In particular, the review is to consider the appropriate future role for transmission in providing efficient services to the competitive sectors of the NEM. This chapter:

- sets out the Commission's view as to how the NEO should be applied when considering these matters; and
- discusses the inter-related nature of transmission frameworks and the implications this has for the role of transmission in the market.

3.1 Application of the NEO

We are required to have regard to the NEO in every review or Rule change 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.

The key 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 operating the transmission system.

A key factor in our assessment will therefore be to consider whether the existing frameworks meet the objective of ensuring that investment and operational decisions across generation and transmission are optimised in a manner that minimises the total system costs imposed on consumers.

In particular, we will consider whether the existing transmission frameworks promote the alignment of efficient decision making and trade-offs across generation and transmission such that overall efficiency is promoted. It will also be important to consider the impacts of existing transmission frameworks on decision making by large and medium loads that connect to the system, and similarly whether decision making is optimised across transmission and load.

In order to address these questions, it is important to understand and properly define the role of transmission as a service provider in the NEM. This includes considering the nature of the services currently provided by TNSPs to generation and load, and determining whether there is scope for services to be provided more efficiently or for new services to be provided in order to promote efficient investment and operation. Similarly, it will also be important for the review to consider the framework under which generators determine investment and operational decisions and the extent to which these are influenced by the services provided by TNSPs and the costs associated with these services, including whether these costs are targeted at the generators that benefit from them.

As we have outlined above, we would encourage respondents to identify those areas where transmission services are considered to be inadequate or would benefit from enhancement. To the extent that concerns are raised regarding the adequacy of transmission services we also encourage participants to provide evidence to support their concerns as well as ideas on how services could be improved.

Question 1 Application of the NEO

Do frameworks governing electricity transmission allow for the minimisation of total system costs and for overall efficient outcomes in accordance with the NEO? What evidence, if any, is there to demonstrate that this is or is not the case?

3.2 The role of transmission and the integrated nature of transmission frameworks

3.2.1 Interactions between framework areas

Transmission frameworks are complex and highly integrated.

The provision of transmission services profoundly affects the competitive wholesale market in the NEM; in the long term from an investment perspective and in the short term from an operational perspective.

There are significant interactions between long term and short term issues. To the extent that TNSPs fail to invest efficiently in the long term, this is likely to place significant pressures on networks in the short term in the form of congestion.[14] While it is inefficient to build out all the risks of congestion (i.e. the optimal level of congestion is not zero), inefficient under-investment in the network will prevent generators accessing the wholesale market and lead to risks of inefficient bidding behaviour by generators to avoid being "constrained off" the system. This will ultimately impose costs to customers.

Under the current NEM arrangements, generators face the risk of being constrained off the network as a result of network operational problems or congestion. This uncertainty may raise contractual risk premiums and potentially hinders efficient generation investment. In particular, to the extent that generators are unable to obtain financial certainty over access to the transmission system, this may impact on their ability to finance the costs of new generation facilities in the long term.

14 Congestion is explored in more detail in section 5.4.

A comprehensive approach therefore needs to be taken to the development of transmission frameworks across both the short and long term. We propose to approach this by considering the nature of the service being provided by transmission networks.

3.2.2 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 customers or generators.

The service currently provided by TNSPs is driven by transmission reliability standards. These standards are prescribed on a jurisdictional basis. As this service is focussed on meeting demand, the costs of the assets that comprise the shared transmission network are recovered solely from load.

The NEM operates under an open access system, where a generator's "right" to use the transmission system depends on whether it is dispatched by AEMO. Where a generator is unable to access the wholesale market as a result of a transmission outage or network congestion it has no means of recourse to the TNSP (or AEMO) for any failure in service delivery or entitlement to any compensation for this.

Furthermore, when a generator is considering investing in new plant it has no means of managing such risks associated with that plant in the future. Even if augmentation of the shared network is deemed to be economically beneficial to customers, a generator has no means of managing the risk that the augmentations are not delivered in a timely manner. While there is scope for generators to fund network augmentation, the nature of the open access regime implies that generator funded network augmentations do not bestow any physical or financial rights to the network. (This issue is discussed further in Chapter 4.)

The presence of such risks may increase financing costs for new generation and discourage investment, at a time when significant investment in new generating plant is likely to be required. Similar concerns may exist for parties considering investing in plant or processes that represent a large system load.

The services provided by transmission

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. This could include the provision of additional or different services to load customers, as well as potentially to generators.

In particular, we are to examine the nature, incentive properties and effectiveness of the existing access arrangements and alternative approaches to transmission service provision.

Transmission currently plays an important role in facilitating the functioning of the market, although this is not an explicitly defined role, unlike the meeting of reliability standards. The development of any alternative approach to service provision would, however, raise a number of important issues for consideration. These are discussed below:

- **Service levels.** Consideration would need to be given to the nature and the definition of the services to be provided. For instance, these could either be specifically negotiated between the TNSP and the connecting party or could be generically defined for the network as a whole. The service level could either relate to physical transfer capability at the connection point, or financial access to the market price. Related to this question would be the nature of any compensation arrangements associated with the non-provision of transmission services. These might apply to specific connection agreements or an administered compensation mechanism could be introduced for the failure to provide capacity.

- **Regulatory and incentive issues.** It is likely that obligations would need to be placed on TNSPs to ensure that minimum service levels are provided. Additionally, incentives could be put into place to drive the delivery of services in a timely and efficient manner, and to ensure that efficient trade-offs are made between capital and operational expenditure. Consideration would need to be given to the level of risk and reward that TNSPs are exposed to, and to the linkages with the nature of the service levels, in particular any compensation requirements.

- **Service provision.** Transmission services can be provided either through investment in networks or through the use of operational (non-network) measures. It may therefore be appropriate to carefully consider the respective roles of TNSPs and AEMO, as system operator, in the provision or procurement of transmission services. A relevant factor would be the ability of the parties to make efficient trade-offs between the different methods of service provision and the incentives that could be put in place.

- **Network planning.** If different services were offered to load or generation, it is likely that there would be implications for the existing planning framework which would need to be considered. For instance, to the extent that specified levels of service were provided to individual generators, this might provide additional information for network planning.

- **Pricing.** In developing any new transmission services, it would be necessary to give consideration as to which parties should be charged and on what basis. The nature of the signals given, for instance with respect to consumption or production decisions or locational choices, would be of particular importance.

Any revised role to be played by transmission in the market, including the development of different or additional services, would be likely represent a significant change to the existing transmission frameworks. As such it would warrant careful consideration, development and assessment in the later stages of this review. This would aim to determine whether any changes in the services provided by TNSPs would help to align the incentives of generators and TNSPs, and therefore ultimately enhance the NEO by providing long term benefits to consumers, through the minimisation of total system costs.

We would welcome views from stakeholders on the appropriate role of transmission in the future and whether there would be merit in the further development of the services to be provided by transmission. In particular, we would welcome views as to whether the market facilitation role played by transmission would benefit from clearer definition and focus.

Additionally, in considering the key issues associated with the current arrangements identified in the remainder of this paper, it should be recognised that there is the need to do so in a holistic manner with a view to addressing this overarching question.

Question 2 The role of transmission

Is there a need to consider the appropriate future role of transmission in providing services to the competitive sectors of the NEM? What evidence, if any, is there to suggest that the existing service provided to facilitate the market, or the definition of this service, is inappropriate or insufficient?

4 Key issues for efficient investment

4.1 Introduction

This chapter identifies the key issues associated with the existing frameworks governing investment in the transmission network and generation. The chapter is divided into three sections:

- the objectives and challenges for efficient network and generation investment;
- transmission investment, which focusses on the frameworks for transmission planning, investment and economic regulation; and
- network charging, access and connection, which discusses the frameworks applying in these three key areas.

4.2 Objectives and challenges for efficient network and generation investment

4.2.1 Objectives

One of the key facets of the NEO is the promotion of efficient investment in electricity services in the long term interests of consumers. This implies that transmission frameworks should promote efficient investment in the shared transmission network and generation plant to deliver reliable supply from generators to load at least cost.

In order to make efficient investment decisions, the transmission planning framework should ensure that transmission businesses have access to robust information relating to future demand for network services by generators and loads, and receive the right incentives to respond efficiently to market signals.

Monopoly transmission businesses should have appropriate regulatory incentives and obligations to ensure efficient and timely investment in response to changing demand for transmission services over the medium to long term. TNSPs should also trade off the cost of augmenting the network with the costs of managing congestion, noting that building out all constraints is unlikely to be efficient.

Information and price signals should provide financial incentives for generators and load to make efficient location decisions by trading off the costs they impose on the shared transmission network with other relevant decision factors such as proximity to fuel source. Market price signals should also encourage generators to invest in the appropriate fuel type (such as wind-powered or gas-fired plant) and technology (such as baseload or fast-start plant).

Importantly, however, transmission frameworks should not be so complex as to impose unnecessarily high transactions costs or to deter entry. Any such arrangements would lead to additional costs to consumers, both directly and potentially through lessening competition.

Finally, regulatory certainty and stability of market frameworks is important to encourage investment. Although this review may appear contrary to this objective, it is our intention that at its conclusion we will have set a clear direction for transmission frameworks in the long term, and that this will act to resolve many long-running debates in this area.

4.2.2 Challenges

Given the large scale investment in generation plant required in future years and the particular changes that climate change policies are intended to drive, it is likely that flows on the transmission network will alter significantly. Substantial transmission investment and expansion may therefore be required. TNSPs will need to be responsive to broader market developments across the generation sector when undertaking network planning and augmentation. The ability of the existing transmission planning frameworks to provide robust information from market participants of future generation, as well as load, requirements is likely to be tested.

Transmission frameworks must provide appropriate incentives for efficient and timely investment in transmission in response to these changing generator profiles. Different and uncertain patterns of flows across the network and substantial new generation investment away from traditional locations will potentially increase the risks that networks will under-invest in certain areas and over-invest in others. Processes and incentives on TNSPs need to be resilient to ensure that efficient projects are identified and implemented.

Further, the timeliness of transmission investment may also become an issue. It is possible that new generation plant will be able to become operational in a shorter timeframe than significant network extensions or augmentations to the shared transmission network can be planned and constructed. This raises a question as to whether TNSPs should also be more proactive when planning and investing in the shared network (although the associated risks would need to be considered).

Future entry by new generating plant, particularly renewables, has the potential to increase the transmission network investment required to facilitate flows between regions. It is likely that renewable generation will be concentrated in certain regions, given the distribution of renewable fuel sources. This may lead to increased power exports from those regions and increased imports into other regions.

Frameworks to support efficient transmission investment should be complemented by frameworks that promote efficient network use by generators and load to minimise overall costs. Climate change policies may test the incentive frameworks that influence where generators locate and when they retire. To date, these frameworks have not had to manage such a significant volume of new investment and retirement decisions.

The remainder of this chapter considers the ability of the existing arrangements to meet these challenges.

4.3 Transmission investment

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 relevant frameworks support the safe, secure and reliable delivery of power to loads and define the "default" level of transmission service that is provided. While TNSPs are tasked with network investment in their own regions, recent reforms to the transmission frameworks are intended to support a greater national focus to the planning and development of transmission across the NEM.

In the longer term, 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.

4.3.1 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.[15] 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 power quality and reliability requirements vary between jurisdictions and are generally open to interpretation and application. To provide greater consistency across the NEM, the AEMC has recommended a national framework for transmission reliability standards.[16] However, this framework has not yet been implemented.

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. To address this, 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

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15 For "declared networks" - currently only the transmission network in Victoria - the basis for network planning is stipulated in the NEL.

16 AEMC 2008, *Transmission Reliability Standards Review*, Final Report to MCE, 30 September 2008, Sydney.

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.

At the same time, generator location decisions will place pressure on transmission planning frameworks. While the NTP is new and largely untested, the information provided by it will need to be sufficiently dynamic to deal with uncertain long term changing patterns of generation and load (including demand side response), and their associated network impacts.

To the extent that more market-based signals could be incorporated into the planning frameworks, these may be more flexible and responsive to future changes in the market than administrative measures, including as a result of future government policy. There may therefore be merit in considering whether there are market mechanisms that could be used to improve investment signals and build on or supplement existing planning arrangements.

Question 3 Transmission planning

Does the current transmission planning framework appropriately reflect the needs and intention of the market (including generators, loads and demand side response)? Will this adequately provide reliable information to TNSPs on where and when to invest, or when to defer or avoid investment, in an uncertain planning environment, or is there a case that additional market-based signals might be beneficial?

4.3.2 Promoting efficient transmission investment

The economic framework for the identification of efficient transmission investment projects has, from 1 August 2010, been provided by the new Regulatory Investment Test for Transmission (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.

Submissions to the Review of Energy Market Frameworks in light of Climate Change Policies raised concerns that, despite the changes to the regulatory test, insufficient network investment will be undertaken to support new entry by generators or to ensure incumbents are unaffected by new entry (and therefore remain able to access the market).[17] In particular, some generators questioned whether the RIT-T would facilitate the timely build-out of intra-regional congestion where it delivered net market benefits. Stakeholders also expressed concern that the planning and RIT-T processes would result in a significant lag in transmission investment that would lead to congestion in the short and medium term.

As noted in the CCR Final Report, we recognise that these reforms are untested and that the responsiveness of transmission will become increasingly important with the implementation of the expanded RET.

We also note that, while TNSPs may be more likely to test potential market benefits investments, 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. Whereas augmentations that are predominantly meeting a reliability standard can proceed on a least cost basis, a proposed augmentation that is primarily to improve the efficiency of spot market outcomes must yield a net benefit to the market.[18] It may be difficult for some types of market benefits, particularly competition benefits, to be demonstrated.[19]

Further, there has traditionally been an emphasis on reliability projects and, 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.[20] 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) vested in the AEMC is a mechanism for triggering cost-benefit assessments of potential projects if TNSPs are not responding to a material problem is a timely manner. The LRPP is 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.

17 AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, Sydney, pp.33-34.

18 This is likely to be more problematic for interconnector investment because it is less likely to be linked to a jurisdictional reliability requirement.

19 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.

20 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.

While the NTP (and the LRPP as a fall-back) will promote the testing of new transmission projects and the RIT-T should ensure that new investment is efficient and help identify projects that maximise net market benefits, these reforms do not extend as far as ensuring that TNSPs will undertake all such investments. Given the anticipated increase in the prevalence and materiality of congestion, we intend to consider whether current arrangements appropriately provide for efficient augmentations to relieve congestion to be undertaken, and to be done so in a timely manner. This will include an assessment of the effectiveness and linkages between the elements of the current frameworks, as well as potentially examining other types of incentive arrangements. Such an approach could involve rewarding TNSPs for investing efficiently (for instance, in response to market signals) and, conversely, exposing them to risk for under investment. This is considered further below.

Question 4 Promoting efficient transmission investment

Will existing frameworks, including the recently introduced RIT-T, provide for efficient and timely investment in the shared transmission network?

4.3.3 Economic regulation of TNSPs

Chapter 6A of the Rules sets out the framework that provides TNSPs with sufficient funding for the provision of transmission networks and provides incentives for efficient, adequate and timely investment in new and replacement network capacity. This aims to align the incentives for TNSPs in relation to investment in, and operation of, transmission networks with those of network users in order to deliver efficient outcomes. At the same time, the Rules are intended to provide a certain regulatory environment for efficient long term investment by both TNSPs and transmission users.

Prescribed transmission services are those services that are provided by shared network infrastructure. These services can only be provided by a single party because of the strong economies of scale and network externality benefits associated with shared network infrastructure.[21] Consequently they are subject to a greater level of economic regulation than other services.

The Rules provide for a revenue cap to be set for each TNSP for prescribed services. The revenue cap is set for periods of at least five years, using a building blocks cost of service approach. This framework provides financial incentives for TNSPs to reduce costs over time because they retain (or are exposed to) differences between actual and allowed revenues for the duration of the revenue period.[22]

At the end of each revenue reset period the revenue allowances are rolled forward based on the value of actual (as opposed to forecast) capital expenditure. This means

21 It is possible, however, that the provider may procure these services on a competitive basis.

22 It should be noted that the transmission network in Victoria is procured and provided by AEMO, which is not subject these incentives.

that TNSPs are not exposed to the costs (other than the initial financing costs) of any inefficient over- or under-investment.

The incentives framework is designed to balance the need to encourage investment in new capacity by lowering regulatory risk faced by TNSPs when investing, and ensuring that TNSPs undertake such investment efficiently so that customers do not pay more than necessary for transmission services. This is a difficult balance to achieve, and the current framework will be tested as the changing profile of generation leads to significant transmission network investment and expansion.

The lack of an *ex post* prudency test provides a more certain investment environment for TNSPs, in that it removes the risk of assets being "stranded".[23] However, this also implies that TNSPs have a relatively weak incentive to minimise capital expenditure and maximise the value of the network services provided, since capital expenditure is rolled into the asset base in perpetuity. Further, there is no accountability for a particular investment to deliver its design capability.

We intend to consider, therefore, whether there is scope to explore additional *ex ante* market based incentives on TNSPs to deliver timely and efficient investment decisions. Linking *ex ante* market based incentives to service delivery and transmission investment could give greater accountability to TNSPs to optimise investment to deliver greater value to network users. Incentives of this nature might set out in advance a clear risk and reward framework that a TNSP's future performance would be measured against. The development of robust financial incentives may help to improve the timing and efficiency of investment decisions, increasing certainty for generation and load over transmission service levels.

Question 5 Economic regulation of TNSPs

Does the current regime for the economic regulation of transmission lead to efficient network investment? Do the incentives on TNSPs lead to appropriate investment decisions and the efficient delivery of additional network capacity?

4.4 Network charging, access and connection

Chapter 6A of the Rules also provides the framework for TNSPs to recover the costs of providing transmission assets through levying charges on participants. It regulates the prices that may be charged by TNSPs for the provision of prescribed transmission services and sets the basis for the charging of negotiated transmission services. For prescribed transmission services, a TNSP must charge in compliance with its published pricing methodology, which is approved by the AER for the duration of the regulatory control period.

23 Under an ex post prudency test, if an asset was deemed to be stranded, or not used, there would be a case for it being removed from the regulatory asset base, and the TNSP would consequently not be able to recover revenue associated with its provision.

4.4.1 Network charging for generation and load

The Pricing Principles for prescribed transmission services in Chapter 6A 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 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.

Generators can influence network costs by either bringing forward or delaying the need for transmission investment. The absence of a price signal to generators of transmission network costs and the impact of locational decisions on these costs may result in inefficient overall locational decisions that increase costs unnecessarily.

This lack of price signals means that appropriate 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) are not made. Although there are a range of factors that impact on the locational decisions made by generators, including access to fuel sources, the risk of constraints and the costs of transmission losses, generator proponents have no direct incentive to locate at points which would minimise the likelihood and extent of network augmentation. As the costs of any such augmentations are recovered from load customers, there is a risk that costs to consumers will be higher than necessary.

To address this framework gap, in the CCR Final Report 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.[24] This charge would vary by location to reflect the differences that a generator's location decision has on network costs, and would therefore require generators to internalise the network cost consequences that result from their location decision.

Options for a transmission charge for generation

During the Review of Energy Market Frameworks in light of Climate Change Policies, we explored a number of options for amending the transmission charging framework, including a use of system charge for generators and "deep" connection charges. While, in principle, both forms of charge could deliver the same locational price signal to a generator, we also noted a number of differences between the two mechanisms. In

24 For further details of our recommendation for the introduction of a locationally varying transmission charge to signal network costs to generators, 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.

particular, whereas an upfront connection charge will affect generators' entry decisions, an ongoing use of system charge would also influence the subsequent decision of whether to keep generation plant in service. A signal that informs timely retirement decisions would free up spare capacity for more efficient plant, ultimately leading to more efficient utilisation of the network.

While we did not recommend a specific form of charge, we did note a preference for a use of system charge. However, we concluded that further work was required to assess the relative merits of a use of system charge against a range of viable alternatives, as well as further develop the design of any potential use of system charges. This review will form the vehicle for that work, and we intend to explore these issues in further detail in subsequent consultation papers.

Transmission charging for load

As noted, all the costs of the provision of the shared network are recovered from load, and load does face locational costs signals under existing pricing methodologies. Although pricing methodologies vary between TNSPs, all TNSPs are required to calculate the locational charges imposed on load using either Cost Reflective Network Pricing (CRNP) or modified CRNP methodologies. However, these methodologies are designed to allocate the full costs, rather than the marginal costs, of assets to users.

In recognition that this 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.[25] 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.

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, in that, 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.

Currently, the costs of transmission in a region are recovered solely from load within that region. However, in the CCR Final Report, we concluded that these arrangements should be amended, as they will result in implicit cross-subsidies when there are positive net flows between regions. We recommended the introduction of inter-regional transmission charges, such that importing regions would pay for the use of the transmission system in exporting regions 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.[26]

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

26 For further information, see: AEMC 2010, *Inter-regional Transmission Charging*, Consultation Paper, 13 May 2010, Sydney.

Question 6 Network charging for generation and load

Is a price signal of locational network costs for generators required to promote overall market efficiency? Would there be any consequential impacts on transmission pricing arrangements for load?

4.4.2 Nature of access

The NEM currently operates under an "open" access system, where a generator's "right" to use the transmission network depends on whether it is dispatched by AEMO. Generators have a limited ability to manage their exposure to dispatch uncertainty. In the presence of network congestion, generators face a risk of not being dispatched - being constrained off the system - or, in some cases, being constrained on. (This is discussed further in the next chapter.)

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. New investment decisions can also be affected, as investment financing is more difficult to obtain for projects exposed to variable, uncertain revenue streams.

The existing default level of transmission service will expose generators to some level of dispatch risk because not all transmission congestion will be built out. This highlights a potential disconnect between the level of transmission service currently delivered by TNSPs and that valued by some generators.[27]

The service that TNSPs are currently required to provide is focussed on transporting sufficient power to meet total load. There are few obligations on TNSPs in relation to the service provided to individual demand customers (although some may exist in individual connection agreements).

The Rules do additionally provide for the negotiated enhancement of the shared network. Under these arrangements, generators or load customers are able to fund network augmentations where the quality of access desired is greater than can be justified under the RIT-T. However, the nature of the open access regime implies that funded network augmentations do not bestow any physical or financial rights to the network.

Existing provisions for negotiated access rights

Rule 5.4A, which provides for generators and load to negotiate financial access to the shared network, is partly intended to address these issues by providing a mechanism

27 This concern was raised during the Review of Energy Market Frameworks in light of Climate Change Policies. For further information, see: AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, 30 September 2009, Sydney, p.35.

for generators to manage dispatch uncertainty. However, in the CCR Final Report, we 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, that TNSP would have no way of hedging 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.[28]

In the CCR Final Report, we concluded that, although the ability for generators to pay for an enhanced level of transmission service would be an appropriate mechanism for managing dispatch risks, Rule 5.4A is unworkable in this context. Given the anticipated increase in the prevalence and materiality of congestion, we therefore proposed to further investigate the implementation of alternative arrangements, such that generators should be able to pay for and receive an enhanced level of transmission service. This will now be progressed as part of this review.

Hedging of inter-regional congestion

The existing frameworks do provide a mechanism for partially managing inter-regional transmission constraints, as generators are able to compete through auctions for a share of the inter-regional settlement residues as a means of hedging inter-regional price differences. Given the potential increases in interconnector flows (and NTFP flows more generally) identified during the Review of Energy Market Frameworks in light of Climate Change Policies, we asked stakeholders whether there was merit in investigating possible options to use external funds to improve the "firmness" of these risk management instruments. There was, however, little support for such a change in its own right.[29]

Nevertheless, the development of firmer access rights, particularly on an intra-regional basis, may have the potential for providing more certainty for generators, and therefore potentially facilitating investment in new generation facilities. We would consequently welcome views from stakeholders on this issue.

Question 7 Nature of access

Would it be appropriate for generators and load to have the option of obtaining an enhanced level of transmission service? Would this help generators to manage risks around constraints and dispatch uncertainty?

4.4.3 Connection arrangements

As noted, generators pay only for their direct connection to the shared network. These connections are treated as negotiated transmission services, as they are dedicated to a specific party.

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

29 Ibid, p.41.

The regulatory regime for negotiated services is less intrusive than that for prescribed services, reflecting that there are likely to be fewer market failure concerns in relation to these services. End-users are likely to be larger and better resourced, acting as a counterweight to the market power possessed by TNSPs and making commercial negotiation a feasible proposition. The service provided may also not be sufficiently similar across users to apply a generic pricing framework. Consequently, the Rules specify that generators and large end-users should negotiate with TNSPs to set prices, service and reliability offerings. This is supported by a dispute resolution mechanism.

Although TNSPs may be constrained in the exercise of market power, there is a risk that they will not be sufficiently responsive and flexible to the anticipated increase in new connections. As discussed previously, significant new investment is anticipated, much of which is may be clustered in certain geographic areas. The framework needs to ensure that TNSPs are able to connect new generation plant at an efficient price with an agreed level of service and quality in a timely manner.

In the Review of Energy Market Frameworks in light of Climate Change Policies, we identified a specific issue related to the efficient connection of clusters of new generation that are expected to seek to connect in the same location over a period of time, and therefore recommended the introduction of new arrangements to address this. The MCE has subsequently endorsed this recommendation and proposed the Scale Efficient Network Extensions Rule change to this effect. The Commission has commenced the consultation process for the Rule change, and a Consultation Document has been published.[30]

We are considering the SENEs Rule change request separately to this review. However, we note that some of the potential issues associated with the SENEs framework identified in the Consultation Document may, in principle, apply more widely to connection arrangements. In particular, the existing framework may not adequately address the potential for connection assets to be shared between a number of users or to be subsequently absorbed into the shared network.

The existing frameworks that support new generator connections are intended to provide TNSPs with sufficient incentives for the efficient connection of new generation plant, based on historical patterns of generator entry. However, to the extent that more fundamental reforms to transmission are examined under the review to manage the challenge of connecting significant amounts of new generation, particularly potentially remote renewable plant, we intend to consider whether it would be appropriate to revisit these frameworks.

30 AEMC 2010, *Scale Efficient Network Extensions*, Consultation Paper, 1 April 2010, Sydney

Question 8 Connection arrangements

Do current arrangements for the connection of generators and large end-users reflect the needs of the market? To the extent that more fundamental reforms to transmission frameworks are considered under the review, would it be appropriate to revisit the connection arrangements?

5 Key issues for efficient operation

5.1 Introduction

This chapter identifies the key issues associated with the existing frameworks governing the operation of the transmission network and the dispatch of generation. The chapter is divided into three sections:

- the objectives and challenges for efficient network operation and market dispatch;
- network operation, which focusses on the frameworks to encourage TNSPs to maximise network availability and to allow for the reporting of this; and
- dispatch of the market and management of congestion, which discusses the frameworks applying in these key areas.

5.2 Objectives and challenges for efficient network operation and market dispatch

5.2.1 Objectives

In the short term, transmission frameworks should promote efficient dispatch outcomes while delivering reliable supply when the market values it most. For transmission this implies that TNSPs have incentives and obligations to operate their network to make capacity available during periods of demand and facilitate effective competition between market participants.

Pricing signals should provide incentives for competitive generator behaviour, meaning generators offer their capacity to the market at cost-reflective prices. Access to mechanisms to manage dispatch and trading risks effectively and efficiently should reinforce the incentives for competitive behaviour. Pricing signals should also provide incentives for load to efficiently manage consumption decisions.

In addition, the regulatory arrangements should promote transparency and the release of information on network availability (including maintenance and outages) to help inform efficient generator production and load consumption decisions.

5.2.2 Challenges

Significant investment in generation is likely to lead to changes in the mix of generation plant, its location and relative competitiveness. In particular, changes in the merit order of generation are anticipated, with greater generation by renewable plant and associated gas-fired back-up generators, leading to consequential changes in network utilisation and flows.

As a result of these changes, and as investment in the shared transmission network may not keep pace with the speed of new generation investment, an increased prevalence of network congestion appears likely.

While some of this congestion will eventually be relieved through network investment, there is likely to be a greater need, at least in the short term, for TNSPs to operate their networks so as to optimise capability and minimise inefficiencies associated with congestion. The incentives on TNSPs to manage and maintain the network to ensure it is available at times when it is of most value to the market are therefore likely to become increasingly important, particularly in light of the potential impacts of extreme weather events on demand levels and operating conditions. While TNSPs are subject to incentive schemes governing the operation of their networks, we consider that the anticipated changes to network flows raise important questions regarding the role and nature of transmission services and the extent to which TNSPs are currently exposed to the market impacts of their operational decisions.

At the same time as considering TNSP incentives, pricing frameworks should also ensure that generators have an incentive to offer their generation capacity to the market at cost-reflective prices. This will increase the likelihood that demand will be met using the least-cost mix of generation. Network congestion can impede efficient dispatch outcomes by encouraging non-cost reflective bidding behaviour (for example, bidding low or negative prices to ensure dispatch). The increased risks faced by generators as a result of congestion may therefore reduce their contracted volumes or lead them to factor in risk premiums, resulting in higher prices. These impacts, and the potential for their mitigation, are discussed further below.

5.3 Network operation

As set out above, it is important that TNSPs operate 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. Short term network operation should therefore ensure that network capability is available for generators to be able to access the wholesale market, particularly at times when the market most values network capacity.

5.3.1 Managing network capability

TNSPs are required to operate their networks subject to a number of obligations set out in the Rules and jurisdictional legislation and licences. These obligations place requirements on TNSPs to operate their networks in a safe, secure and reliable way. In maintaining the secure operating state of the transmission network, TNSPs will also maintain or increase its power transfer capability.

Small changes to the capability of the existing network can substantially ease congestion. Enhanced network capacity, particularly at certain times such as elevated demand levels triggered by heat waves, may therefore help alleviate the physical and financial trading risks associated with congestion.

TNSPs can influence network capability through:

- maintaining and operating network elements to ensure that their capacity is maximised, for instance through the use of dynamic ratings;
- scheduling network outages at times when the value of network capability is relatively low;
- the procurement of Network Support Services (NSS) from third parties; and
- the delivery of Network Control Services (NCS) from their own assets.

NSS and NCS are forms of Network Support and Control Services (NSCS). NSCS are services which provide the capability to control the active or reactive power flow into or out of a transmission network.

Under the Rules, AEMO has a role in ensuring that appropriate levels of NSCS are available in order to ensure that the power system security and reliability standards are achieved.[31] NSCS procured by AEMO are referred to as Network Control Ancillary Services (NCAS). AEMO may additionally procure NCAS to increase the benefits of trade from the spot market (which would be achieved by increasing the capability of the network).

To clarify the roles of TNSPs and AEMO, AEMO has reviewed the existing arrangements for NSCS, and has subsequently lodged a Rule change request with the Commission. We have recently commenced the consultation process for this, and a Consultation Document has been published.[32] We intend to consider this Rule change separately. However, the review will need to recognise any potential changes to the existing arrangements in this regard.

5.3.2 Incentives for improving network capability

As discussed, it is anticipated that the materiality of congestion is likely to increase over the short to medium term. 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.

The existing incentive framework sets out the principles for a Service Target Performance Incentive Scheme for TNSPs, developed by the AER. Under the Rules, up to 5 per cent of a TNSP's regulated revenue can be put "at risk" if measures of performance are not met.

31 The power system security and reliability standards are approved by the Reliability Panel on the advice of AEMO, and may include (but are not limited to) standards for reserves and frequency.

32 AEMC 2010, *Network Support and Control Ancillary Services*, Consultation Paper, 22 July 2010, Sydney.

The Service Target Performance Incentive Scheme 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 currently comprised of two components:[33]

- 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 network outage constraint with a marginal cost that exceeds $10/MWh.[34]

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.

A limiting factor on promoting efficient transmission services from the perspective of congestion management is the absence of the "outputs" that matter from a congestion management perspective, i.e. transmission capability. The Service Target Performance Incentive Scheme is an important element in promoting efficiency, but is necessarily based around partial output measures in the absence of more general metrics of transmission capability.

5.3.3 Information on network capability

The ability of market participants to manage the physical and financial risks arising from network congestion depends on the quantity, quality and timeliness of the information available to them. While it is important that TNSPs maximise network capability, it is critical that there is sufficient transparency for market participants to understand the impacts of any actions taken by TNSPs. Investors also require information in order to make efficient locational investment decisions for building new transmission and generation capacity.

In the Congestion Management Review we examined the information that was available to help participants understand and manage congestion. We identified two

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

34 The Commission has recently determined that new provisions should be introduced into the Rules to allow this component to be applied to TNSPs prior to their next revenue reset. For further details, see: AEMC 2010, *Early Implementation of Market Impact Parameters*, Rule Determination, 11 March 2010, Sydney.

areas where greater information provision was warranted, taking into account the costs of collating and publishing additional information:[35]

- real-time information on planned network events affecting dispatch; and
- information on the incidence and patterns of mis-pricing.

To implement these, we recommended that AEMO be required to publish a single, central resource for congestion-related information - the Congestion Information Resource (CIR). The purpose of the CIR is to make information available to market participants to enable them to understand patterns of network congestion and make projections of market outcomes in the presence of network congestion. AEMO has now established an interim CIR, with the final version due in September 2011.

AEMO is also required to report on the existing and future dynamics of network capability and congestion as part of its annual NTNDP. This will require AEMO to develop a suitable measure of network capability, which may help inform enhancements to the AER's Service Target Performance Incentive Scheme.

The information released should help inform efficient operational and investment decisions by all market participants. Generators and large customers can make more informed bids if they have better information about which constraints will be included in dispatch. Information on mis-pricing will help inform investment location decisions, identifying possible congested areas and therefore prompting a comprehensive assessment of congestion at a preferred location.

To the extent that congestion is likely to increase, it will become even more important to ensure that market participants understand the nature and level of congestion on the network so as to inform efficient generator behaviour. We therefore intend to consider further options for information release, for instance in relation to unplanned network outages, and would welcome views from stakeholders on this issue.

Question 9 Network operation

Are more fundamental reforms required to financial incentives on TNSPs to manage networks efficiently and to maximise operational network capability for the benefit of the market? Should further options for information release and transparency on network availability and outages be considered?

5.4 Dispatch of the market and the management of congestion

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.

35 See: AEMC 2008, *Final Report*, Congestion Management Review, June 2008, Sydney, Chapter 3.

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 the five year period between 2003-04 and 2008-09, the costs of transmission congestion in the NEM totalled more than $0.5 billion, with annual costs generally trending upwards over that period.[36]

In order to mitigate the risks associated with congestion, generators may engage in behaviour that leads to further inefficiencies in the market, and this is also discussed below.

5.4.1 Mis-pricing 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 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 loads in that region to consume less. In the longer term, price differences 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 "mis-pricing", in that the Regional Reference Price (RRP) used for settlement is different to the hypothetical prices for each node that would reflect local demand and supply conditions.

Mis-pricing creates "dispatch" risk for generators. A generator may 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 (if the generator were to take no other 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

36 AER 2009, *State of the Energy Market 2009*, p.143.

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.

5.4.2 Dis-orderly 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 the price they receive will be set by higher-cost generation elsewhere, and therefore have an incentive not to make cost-reflective offers. They will instead offer capacity at a price which maximises their dispatch. At the extreme, this could be at the market floor price of -$1,000/MWh. This is known as "dis-orderly" bidding, and results in network capacity behind constraints being rationed using non-cost-reflective prices.

The presence of dis-orderly 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, it also creates 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 the previous chapter, reduced certainty of dispatch outcomes will impact financial markets, increasing costs and potentially discouraging investment in new generation plant.

5.4.3 Previous recommendation for the introduction of congestion pricing

In the CCR Final Report, we set out our finding that increased levels of congestion resulting from the effects of climate change policies are likely to result in a higher incidence and increased materiality of dis-orderly bidding by generators, with associated negative impacts on the efficiency of dispatch and contracts markets. We therefore recommended 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.[37]

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

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

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 CCR Final Report that a form of congestion pricing should be introduced. 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:

- 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.

Additionally, we noted that the introduction of such a mechanism would introduce another risk into the market, in that generators contracting with participants at other nodes would be exposed to a risk of differences in nodal prices. While instruments to manage this risk could be included as part of the scheme, the allocation of these could be problematic.[38]

In the CCR Final Report, we indicated that the expected transitory and localised nature of material congestion might support the case for location-specific, time-limited implementation of congestion pricing.[39] However, we also noted that the associated implementation issues would be material, and therefore required further consideration.

This review will allow us to undertake this further development and assessment process. However, it will also provide the opportunity to examine other potential solutions. For instance, in considering the nature of access provided for generators, it will be possible to assess the extent to which changes in this area might address the issues associated with dispatch risk and inefficiency in the dispatch of generation.

38 For further discussion of this matter, see: AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, 30 September 2009, Sydney, Appendix J.

39 Ibid, p.38.

Question 10 Dispatch of the market and the management of congestion

Is there a need for material congestion to be more efficiently managed in the NEM?

Abbreviations

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APR	Annual Planning Report
CCR	Review of Energy Market Frameworks in light of Climate Change Policies
CIR	Congestion Information Resource
Climate Change Review	See CCR
COAG	Council of Australian Governments
CPRS	Carbon Pollution Reduction Scheme
CRNP	Cost Reflective Network Pricing
DSP Review	Review of Demand-Side Participation in the NEM
ERIG	Energy Reform Implementation Group
FNP	full nodal pricing
FTRs	firm transmission rights
IRSRs	Inter-Regional Settlement Residues
LRPP	Last Resort Planning Power
MCE	Ministerial Council on Energy
NCAS	Network Control Ancillary Services
NCS	Network Control Services
NECA	National Electricity Code Administrator
NEL	National Electricity Law
NEM	National Electricity Market

NEMMCO	National Electricity Market Management Company
NEO	National Electricity Objective
NER	See Rules
NSCS	Network Support and Control Services
NSEE	National Strategy on Energy Efficiency
NSS	Network Support Services
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
RRP	Regional Reference Price
Rules	National Electricity Rules
SENEs	Scale Efficient Network Extensions
SRA	Settlement Residue Auction
TFR	Transmission Frameworks Review
the Commission	See AEMC
TNSP	Transmission Network Service Provider

A MCE Direction

MCE

Ministerial Council on Energy

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Australian Energy Market Commission
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20 APR 2010

Dear ~~Dr Tamblyn~~ John

AEMC REVIEW OF TRANSMISSION FRAMEWORKS

I am writing to you in my role as Chair of the Ministerial Council on Energy (MCE) about a review of transmission network frameworks as proposed in your Final Report for the Review of Energy Market Frameworks in light of Climate Change Policies.

As you are aware, at our meeting on 4 December 2009, the MCE considered the findings of the Final Report for the Review of Energy Market Frameworks in light of Climate Change Policies, and released its policy response to your recommendations.

As part of this response, the MCE agreed to ask the AEMC to review electricity transmission network frameworks in consultation with the Australian Energy Market Operator (AEMO) and the Australian Energy Regulator (AER). The review focus is on transmission investment, network operation, network charging, access and connection, and management of network congestion.

Attached is a detailed Terms of Reference for this task.

The MCE looks forward to working closely with the AEMC on this important market development initiative.

Yours sincerely

Martin Ferguson

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TERMS OF REFERENCE – AEMC TRANSMISSION FRAMEWORKS REVIEW

At its 4 December 2009 meeting, the Ministerial Council on Energy (MCE) considered the AEMC's Final Report on its Review of Energy Market Frameworks in light of Climate Change Polices.

At the meeting, the MCE agreed a response which supported the AEMC's key finding that energy markets will generally be resilient to the anticipated impacts of climate change policies. However, the MCE also agreed that further work should be undertaken on the arrangements underpinning the provision and utilisation of transmission networks to improve their integration with the competitive electricity market.

The MCE notes that significant reforms to the framework supporting network investment have been, and are continuing to be, implemented. These include the regulation of transmission revenues, a new Regulatory Investment Test for Transmission (RIT-T) and establishment of the Australian Energy Market Operator (AEMO) as the National Transmission Planner tasked with publishing the National Transmission Network Development Plan (NTNDP). The new transmission planning arrangements were implemented on the basis of the following principles agreed by the Council of Australian Governments (CoAG):

- accountability for jurisdictional transmission 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.

CoAG committed to a review of the effectiveness of these arrangements after five years of their operation.

The MCE notes that the introduction of climate change policies is likely to drive major changes in patterns of generation in the National Electricity Market (NEM), with significant new investment in renewable and low carbon generators. In this regard, the MCE has recently initiated Rule change proposals to provide for Scale Efficient Network Extensions (SENEs) and Inter-regional Transmission Charging to ensure the existing framework is responsive to the challenges the NEM faces in light of climate change policies. The MCE recognises that these proposals could have significant impacts on electricity markets and the provision of timely and efficient new investment in transmission services.

The adjustment and further development of the NEM to address these issues in a timely and efficient manner will represent a considerable challenge, particularly given that much of the new generating capacity is expected to be located in areas remote from load centres and existing networks. These changes come at a time when much of the established network infrastructure is undergoing asset renewal and replacement, and when extreme weather events can impact on the security and reliability of electricity supplies.

The MCE therefore considers that the role of the transmission sector in ensuring that the electricity market is best placed to meet these challenges should be reviewed, recognising recent reforms to the transmission investment framework, with a view to ensuring that the incentives for future investment and operating decisions by generators and regulated network businesses are effectively aligned to deliver an efficient outcome overall. Such incentives should promote the provision of transmission capacity and services where and when required to meet the changing needs of the competitive sectors of the market in a timely, efficient and reliable manner in the long term interests of consumers.

The MCE has therefore agreed to direct the AEMC to conduct a review of electricity transmission frameworks in line with the Terms of Reference detailed below.

MCE direction to the AEMC

Section 41 of the National Electricity Law (NEL) enables the MCE to direct the AEMC to review any matter relating to the NEM or any other market for electricity.

Pursuant to section 41 of the NEL, the MCE directs the AEMC 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, particularly in light of the anticipated impacts of climate change policies and the potential impact of extreme weather events.

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, having due regard for the limited time some of them have been in place. 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.

Where deficiencies are identified in the incentives provided by the market frameworks, the AEMC should consider whether they could be satisfactorily addressed by incremental changes to the transmission arrangements or whether more fundamental changes are required, noting recent and ongoing reforms to the transmission framework. If the AEMC concludes that fundamental changes are essential, it shall consider whether there are any implications for the existing arrangements in the NEM and, if required, identify relevant options for change for consideration by the MCE.

In reviewing the existing arrangements and identifying any options for reform, the AEMC shall have regard to the National Electricity Objective in the NEL and the CoAG agreed principles detailed above. When considering potential proposals to amend the market frameworks, the AEMC should also 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 impacts.

This work should also take into account potential impacts of the new transmission-related measures recommended in the Review of Energy Market Frameworks in Light of Climate Change Policies. The MCE notes in its response to that Review that any future work should take into account the interaction of initiatives, including SENEs and Inter-Regional Transmission Charging.

Specific areas for consideration

In conducting its review, the AEMC shall have regard to the key areas outlined below, as well as any other matters it considers relevant.

These key areas should be considered together in a holistic manner, including assessment of the appropriate future role for transmission in providing efficient services to the competitive sectors of the NEM. The AEMC shall examine the nature, incentive properties and effectiveness of the existing access arrangements and alternative approaches to transmission service provision to the extent necessary for the purpose of this review. This should include consideration of the appropriate allocation and management of costs and risks across the market.

Transmission investment. The AEMC shall consider the extent to which the regulatory framework provides appropriate financial incentives on transmission businesses to ensure efficient and timely service provision. The AEMC should also assess the extent to which the planning framework is effectively aligned with the regulatory process governing transmission investment, including whether sufficiently robust information is provided to inform regulatory decision making. In addressing these issues, the AEMC should consider the impacts of climate change policies and the introduction of the NTNDP and RIT-T.

Network operation. The AEMC shall consider the nature, transparency and effectiveness of the current incentive arrangements governing network operation, availability and efficient service delivery. In particular, the AEMC shall assess whether these arrangements provide network businesses with sufficient financial incentives to operate their networks in a manner that optimises overall network availability and market efficiency.

Management of network congestion. The AEMC shall consider and, as appropriate, develop mechanisms that promote more efficient bidding and pricing behaviour by generators in congested parts of the network. It is key that, in developing mechanisms that address network congestion, the AEMC should assess the extent to which congestion, and measures to manage congestion, may impact on generation investment and the liquidity of forward markets (including intra- and inter-regional contracting). In particular, the AEMC should consider how dispatch and price risks might be mitigated with the objective of providing an increased level of certainty to all market participants.

Network charging, access and connection. The AEMC shall consider the effectiveness of the existing transmission network charging and access arrangements. In particular, the AEMC shall consider the development of improved locational signals for generators, and, if necessary, any implications for transmission pricing more broadly, including transmission pricing for load. The AEMC shall also examine the impacts of the existing access regime on generator investment decisions, and should assess the effectiveness of the current arrangements for connection services for generators.

Establishing a Consultative Committee

In tasking the AEMC to undertake this review, the MCE notes the importance of engaging with the energy sector and drawing upon relevant technical expertise.

In this regard, the AEMC is to establish a Consultative Committee comprising representatives from:

- AEMO;
- the Australian Energy Regulator;
- industry groups and representatives from electricity networks, electricity generators (including renewable generation), and electricity retailers; and
- energy user representatives.

Timing and process

The MCE requires that the AEMC:

- undertake a formal stakeholder consultation process, including the release at least one interim report consulting on its interim conclusions and recommendations;
- if considered appropriate by the AEMC, hold a public forum; and
- provide a final report setting out its policy conclusions and recommendations to the MCE by 30 November 2011.

The AEMC must publish a copy of the final report on its website once MCE has had at least two weeks to consider its recommendations.

B Summary of transmission reviews and reforms

Transmission and Distribution Pricing Review: Final Report (NECA), July 1999

This review by the National Electricity Code Administrator (NECA) assessed transmission and distribution pricing arrangements in the NEM. Recommendations made in the final report, published in July 1999, that related to transmission included the following:

- all parties, including generators, would be required to pay a share of new transmission augmentation costs where they are a “beneficiary” of that augmentation;
- an outline of principles for transmission network pricing;
- an outline of incentive mechanisms to encourage improved service provision. Also developed a framework for negotiated services with NSPs;
- potential enhancements to inter-regional price risk hedging mechanisms; and
- the potential for a transmission congestion contract model, designed to hedge price separation between different network locations.

The scope for integrating the energy market and network services: Stage 1 Final Report (NECA), August 2001

This review assessed the scope for the integration of energy markets and network services. The Stage 1 Final Report, published in August 2001, assessed the Settlement Residue Auction (SRA) arrangements and determined that these were generally effective. However, it also made a number of recommendations to improve the firmness of Inter-Regional Settlement Residues (IRSRs).

These recommendations, set out as a three stage set of improvements, included:

- TNSPs to provide rolling 12 month programmes of planned network outages;
- assessment of the market value of trade forgone because of network outages; and
- contractual obligations placed on TNSPs against network performance targets.

Network and Distributed Resources Code changes: Determination (ACCC), February 2002

In December 2000, the Australian Competition and Consumer Commission (ACCC) received a request from NECA to grant authorisation to a number of amendments to the National Electricity Code. In February 2002, the Commission released its determination in which it approved changes relating to:

- institutional roles and procedures, including changes to the roles and responsibilities of TNSPs, the Inter-regional Planning Committee, the National Electricity Market Management Company (NEMMCO) and the ACCC in relation to the planning and approval of new transmission investments;
- the framework for regulated new investments, in particular the planning requirements associated with different types of network investment; and
- the consultation and dispute resolution process relating to network augmentation proposals.

Towards a truly national and efficient energy market: Final Report (Parer Review), December 2002

At its June 2001 meeting, COAG agreed to commission a review of the strategic direction for energy market reform in Australia. An independent panel, chaired by Warwick Parer, was convened to conduct the review, and it presented its final report in December 2002.

The report identified a range of issues with the then current transmission frameworks. These included: a lack of nationally co-ordinated network planning; a failure to facilitate sufficient inter-regional trade and to address intra-regional congestion; a lack of incentives to encourage TNSPs to respond to market demands; and poor signals and lack of certainty for network investment.

The report made a range of recommendations in relation to these issues. These included:

- NEMMCO be given responsibility for planning the intra-regional and inter-regional network, including providing information, highlighting potential augmentations and managing augmentation through competitive tenders;
- NEMMCO to auction firm transmission rights (FTRs) for a period up to five years in advance, to apply to regulated interconnectors (these FTRs would be funded by settlement residues and auctions);
- the creation of a transparent, market based investment trigger for interconnected augmentations, based on the cost of FTRs;
- TNSPs to be financially incentivised to provide more market responsive network performance, in both the inter- and intra-regional context; and
- an increase in the number of regions in the NEM, with a preference to move to full nodal pricing (FNP) in seven to ten years.

Economic Regulation of Transmission Services: Final Rule Determination (AEMC), December 2006

The AEMC was required under the NEL to review the Rules governing the regulation of electricity transmission revenue and pricing. In November 2006, the Economic Regulation of Transmission Services Rule change (Revenue Rule) developed the mechanisms which define the allowable revenues for prescribed TNSP services, including:

- Contingent Projects: The Revenue Rule allows for "contingent projects" to be identified by TNSPs, that is, capital projects which are sufficiently uncertain that they cannot be included in the initial maximum allowed revenue at the regulatory reset. The intention of this aspect of the Revenue Rule is to provide TNSPs with sufficient flexibility to develop their services as the demands of the market change throughout the regulatory period; and

- TNSP Service Incentives: The Revenue Rule allows for the AER to set service incentives, of up to +/- 5% of regulated revenue, to encourage TNSPs to provide greater reliability of the system at times when it is most valued, and in relation to those elements of the system that are most important in determining spot prices. In effect, this latter requirement incentivises TNSPs to consider the cost of congestion in the network when making operational and investment decisions.

Pricing of Prescribed Transmission Services: Final Rule Determination (AEMC), December 2006

The Pricing of Prescribed Transmission Services Rule (Pricing Rule) was published in December 2006 and developed the pricing component of the review of electricity transmission and pricing. Core components of the Rule included the development of principles for the allocation of TNSP costs and structuring of prices.

A key conclusion was the reaffirmation that the "causer pays" principle remains central to the allocation of transmission network costs. Additionally, generator transmission use of system and deep connection charges were assessed. However, given the market circumstances at the time, it was determined that existing market mechanisms provided adequate locational signals to generators.

Energy Reform: The Way Forward for Australia: ERIG Review, January 2007

At its February 2006 meeting, COAG agreed to the establishment of the Energy Reform Implementation Group (ERIG). ERIG was asked to report before the end of 2006 on a number of reform recommendations relating to the development of the energy sector. ERIG presented its final report in January of 2007.

In relation to transmission issues, the final report examined a number of issues including: a lack of effective commercial locational signals and incentives for generators; the need for improved incentives for both the efficient operation of and investment in transmission networks; and a requirement for coordination of investment in the transmission system on a national basis.

The report made a range of recommendations in relation to:

- the development of the NTP and NTNDP;
- the development of a comprehensive incentive regime for TNSPs;
- the development of national reliability standards;
- the need for the refinement of intra-regional locational signals, although the potential adverse effect on energy financial markets of full nodal pricing were highlighted; and
- the need to improve the design of the instruments supporting inter-regional trade, particularly the SRA process, by providing firmer transmission rights and reducing volume risk.

Abolition of Snowy Region: Final Rule Determination (AEMC), August 2007

In November 2005, the AEMC received a Rule change proposal from Snowy Hydro regarding a change to the existing Victorian and NSW region boundaries which would effectively abolish the Snowy region. The final Rule change and determination took place subsequent to a number of measures which were intended to address the impacts of material congestion in the Snowy region. One measure included the Tumut Constraint Support Pricing/Constraint Support Contract Trial.

The final Rule determination found that abolishing the Snowy region was the most effective and efficient means to address material and persistent congestion in the region. The Commission found abolition would encourage generators to bid more competitively, in turn positively impacting on contract markets and providing clearer signals for efficient investment and consumption in the longer term.

Process for Region Change: Final Rule Determination (AEMC), December 2007

In October 2005, the MCE submitted a Rule change proposal to the AEMC to reform the criteria and process for region change in the NEM. This followed the MCE's earlier response to the Parer Report, where the need for a new and more transparent process for region change had been highlighted.

This Rule change proposal was considered by the Commission with reference to the other Rule change proposals relating to the Snowy region and the abolition of the Snowy region itself. The Commission published its final Rule change determination in December 2007.

The Commission's final Rule determination developed a process for applicant initiated region change. This process includes a requirement for applicants to demonstrate that a proposed region change is designed to remedy instances of enduring and material congestion. Additionally, it requires that the Commission is satisfied that economic efficiency will be improved.

Review of Demand-Side Participation in the National Electricity Market: Stage 1 and 2 Final Reports (AEMC), May 2008 / November 2009

In October 2007, the AEMC initiated a review to determine the extent of effective and efficient DSP in the NEM.

The Stage 1 Final Report of the Review was completed in May 2008 and assessed the current Commission work programme as it related to DSP. The Stage 1 Final Report made a number of recommendations which included consideration of DSP options by the NTP/NTNDP and use of DSP for Network Support Control Services (NSCS).

The Stage 2 Final Report was completed in November 2009 and assessed the broader Rules in terms of how they might promote DSP. The Stage 2 Final Report made several recommendations relating to the economic regulation of networks. These included ensuring that network businesses are not penalised for investing in DSP as a means to defer capital investment, and increasing the incentives available for distribution businesses to innovate for DSP or embedded generation connections.

Congestion Management Review: Final Report (AEMC), June 2008

In October 2005, the AEMC was directed by the MCE to commence a review of the management of congestion in the NEM. The Commission was requested to produce a report which identified the financial and physical risks associated with material congestion and to propose improved arrangements for the management of these risks. The Final Report of this Review was published in June 2008.

Generally, the Report found that congestion in the NEM had not been material to date, with a relatively low cost impact on the NEM as a whole.

The Report proposed a number of improvements that could be made to the congestion management regime. These included:

- publication of constraint formulation guidelines and information;
- clarification of the Rules to allow for adjustments to generator transmission access costs, where generators had funded network augmentation;
- recovery of negative IRSRs from the importing region's TNSP;
- extension of the SRA process to make IRSR units available three years in advance; and
- a model for management of location specific congestion was developed, however this was not recommended for implementation.

National Transmission Planning Arrangements: Final Report (AEMC), June 2008

On 3 July 2007, and further to a COAG decision on 13 April 2007, the AEMC was directed by the MCE to conduct a review to implement the recommendations made in the ERIG Review in respect of the national transmission planning function.

The final report of this review made a number of recommendations which included:

- the establishment of the NTP as one of the functions of AEMO;
- the annual publication by the NTP of the NTNDP, to include reporting likely congestion; and
- the establishment of the new RIT-T to replace the existing Regulatory Test. The RIT-T is intended to identify options which maximise net economic benefits subject to meeting deterministic reliability standards. TNSPs would be required to consider a range of defined market benefits when undertaking project development, including “option value market benefits”, that is augmentations or developments which may result in future market value.

Transmission Reliability Standards Review: Final Report (AEMC), September 2008

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, as recommended by the ERIG Review.

The AEMC requested the Reliability Panel provide advice to inform its report to the MCE. The Reliability Panel presented its final report to the AEMC in August 2008, and the AEMC presented its final recommendations to the MCE in September 2008.

In its final report, the Commission made recommendations for a national framework to promote consistency in transmission reliability standards, and for the implementation of this framework. The key elements of the proposed framework are:

- transmission reliability standards that are economically derived using a customer value of reliability or similar measure, and capable of being expressed in a deterministic manner; and
- standards are to be derived on a jurisdictional basis, by a body independent of the transmission asset owner. There would also be the option for jurisdictions to allow a national body to set their reliability standards.

Review of Energy Market Frameworks in the light of Climate Change Policies: Final Report (AEMC), September 2009

On 13 June 2008, the MCE directed the AEMC to undertake a review to determine whether electricity and gas market frameworks would require amendment following the introduction of the proposed CPRS and expanded RET. The final report of this review was published in September 2009 and made a number of recommendations relating to reliability, wholesale gas and electricity markets, transmission and retail.

In relation to transmission networks, the final report recommended:

- the development of a Rule change allowing for Scale Efficient Network Extensions (SENEs), the intent of which is to ensure that the expansion of the transmission network to connect generation clusters will be efficient;
- the development of a Rule change allowing for Inter-regional transmission use of system charging, designed to improve the overall cost reflectivity of transmission charges;
- a generator transmission charge to signal network costs associated with connection in particular locations;
- that, where feasible, prices received by generators should reflect network congestion; and
- that generators should be able to negotiate an enhanced level of transmission service.

It was recommended that the final three proposals, above, should be further developed, and it was this requirement that has led to the commencement of this Review.