REVIEW

Australian Energy Market Commission

SECOND INTERIM REPORT

Transmission Frameworks Review

Commissioners

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Second Interim Report

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About the AEMC

The Council of Australian Governments (COAG), through its then Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. In June 2011 COAG announced it would establish the new Standing Council on Energy and Resources (SCER) to replace the Ministerial Council on Energy. The AEMC has two principal functions. We make and amend the national electricity and gas rules, and we conduct independent reviews of the energy markets for the SCER.

Executive summary

The Transmission Frameworks Review touches on many of the arrangements that together influence investment in, and operation of, the National Electricity Market (NEM). This is an evolving rather than a static market and does not operate in isolation from the broader economy and policy environment.

The law, rules and institutions that govern the operation of the NEM must also evolve and should allow for efficient outcomes in the context of an uncertain future. It is highly likely that technological developments, changes in the nature of the Australian economy and responses to climate change policy will fundamentally change the way electricity is generated, transported and consumed over coming decades. Attempts to precisely predict the nature and outcomes of those changes will inevitably be inaccurate.

This review provides a timely opportunity to step back and consider what arrangements for transmission are likely to deliver the most cost efficient outcomes over the long term, given this uncertainty.

The regulatory frameworks and planning arrangements for transmission need to allow for efficient outcomes to be achieved under a broad range of scenarios. This is most likely to occur where the combined costs of generation and transmission are taken into account in investment and operational decisions for both generation and transmission, leading to lower costs overall. It is also more likely when those that make investment decisions have a financial stake in the efficiency of outcomes resulting from these decisions.

This Second Interim Report of the Transmission Frameworks Review sets out alternative paths for key aspects of transmission in the NEM, in particular the nature of the relationship between generation and transmission. One of those paths reflects the existing arrangements. The other would have the effect of moving towards a more market oriented approach to the procurement, operation and use of transmission services in the NEM.

This review is being undertaken by the Commission as part of its broader work program to enhance market frameworks to allow businesses and regulators to deliver reliable electricity supply for customers in the most cost efficient way. This requires an electricity market that can adapt to changing circumstances and deliver efficient investment and innovation.

The Commission's current focus is on driving efficient electricity market outcomes through three specific projects:

- Network regulation rule changes – improving the rules for price setting to allow the regulator to make sure that network costs are no higher than necessary to deliver the level of services that customers want.

- Transmission Frameworks Review – to create a flexible framework to deliver the most cost efficient investment in electricity generation and transmission in the future.

- Power of Choice Review – creating a framework to allow innovation and customer choice to drive the most efficient use and delivery of energy services.

The review

This review was commissioned from the Australian Energy Market Commission (AEMC) by the Ministerial Council on Energy (MCE), now the Standing Council on Energy and Resources, in April 2010. It was intended to be a comprehensive review of the fundamental elements of transmission frameworks in the NEM with a view to identifying and securing arrangements that will lead to cost efficient outcomes for customers.

The review has attracted a high level of stakeholder engagement although there has been some polarisation of views about the effectiveness of current arrangements and therefore the need for any change.

Where stakeholders have expressed concerns about current arrangements, however, there has been a high degree of consensus about how alternative arrangements might be best configured. The Commission anticipates that its final report will outline consistent and interrelated reforms that it believes will best lead to the most workably efficient transmission frameworks over the long term.

At this stage the Commission considers that there are likely to be some clear benefits from fundamentally transforming the way in which generators access the market and the way transmission investment decisions are made. At a high level this would result from a better alignment of the economic objectives of the market as a whole with the financial incentives that bear on market participants and investment decision makers.

Introducing an alternative form of access for generators will be a complex process. Careful consideration will need to be given to whether the potential benefits outweigh the risks and costs, not all of which will be clearly quantifiable because it is difficult to forecast future patterns of generation investment and, in particular, how generators would respond to access choices.

This review therefore represents a turning point in the evolution of the NEM: market participants and governments can accept the existing arrangements as broadly appropriate and continue to make refinements over time; or can implement a significantly different set of arrangements. Either way, the Commission considers that the arrangements resulting from this review should remain in place for some years to come so as to provide a stable investment environment.

The report

This Second Interim Report addresses three broad areas of transmission arrangements:

- generators' certainty of access to their regional reference price;
- planning frameworks; and
- arrangements for connecting to the network.

The report draws on the proposals and options set out in the First Interim Report but has narrowed the generator access options from five to two.[1] It also sets out the Commission's proposals for improving planning and connection arrangements.

The revised proposals in this report have been developed following careful consideration of stakeholder responses to the First Interim Report and extensive analysis by the Commission. The development of an alternative approach to generator access has been assisted by analysis of similar approaches proposed by the Australian Energy Market Operator (AEMO), the Australian Energy Regulator (AER) and some market participants.

Generator access

The First Interim Report published late in 2011 set out five alternative paths for dealing with generator transmission "access". By generator access we mean the nature of the access certainty that generators might have to receive the regional reference (or spot) price for their output when their price bids would result in them being dispatched.

This report sets out two options for generator access and related frameworks:

Non-firm access - this approach essentially reflects the access generators have under the current NEM arrangements but with clarification that this is the only access product or service that can be offered to generators. Their access to the regional reference price for their output would be dictated by a combination of being dispatched because they are in merit order and an absence of transmission constraints between their location and the regional reference node. As is currently the case, generators would not pay to use the transmission system and transmission would be planned and operated with a primary focus on meeting demand-side reliability standards.

The key advantage of this approach is simplicity – it is very close to the status quo and is therefore a known quantity. However, for it to produce efficient outcomes that minimise total system costs would require:

- transmission planners to be able to accurately forecast likely market driven generator entry decisions and technological development, and plan their networks accordingly; and
- generators to have foresight of network conditions, including over the very long term when they choose where to locate.

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1 The First Interim Report is available on our website at www.aemc.gov.au.

Optional firm access - under this approach, generators would be able to choose whether to have "firm" or "non-firm" access. Those that choose to be firm (or firm for part of their output) would pay a price to the transmission business that broadly reflects the incremental cost of providing access to the regional reference price.

This model would not ensure that firm generators were always physically dispatched - indeed, the current dispatch process would be unaffected. Rather, when transmission constraints bind, firm generators that were constrained from accessing the regional reference price would be compensated for lost margin, with non-firm generators funding compensation. Non-firm generators would not receive less than their bid price, although they may not receive the regional reference price during such constraint conditions.

Transmission operators would be required to plan and operate the network to deliver the contracted firm access. If they failed to so, they would fund some of the shortfall in compensation to firm generators which would result.

This proposal has the potential to address several key shortcomings in existing transmission frameworks:

- Generators would be able to secure (and pay for) greater financial certainty as producers – leading to lower risk and financing cost for generators and improved contract market liquidity.
- Transmission investment would be partially driven by generators choosing and paying for firm access rather than planners anticipating generator market development and customers paying for all transmission.
- Generator decisions about where to locate would be influenced by the transmission cost differences of firm access at varying locations – generators would need to balance the costs of generation and transmission.
- Rights associated with the use of interconnectors would become firmer, which should improve energy contract liquidity. Investment in interconnectors would also be partially driven by market participants securing and paying for these rights based on their own valuation, rather than resulting from planners' decisions and being fully funded by customers.
- Overall generator dispatch would be more economically efficient. Current incentives for disorderly bidding when the network is constrained would be reduced. Firm generators would be less dependent on being dispatched to earn revenue and non-firm generators would risk receiving a price close to their bid price rather than the regional reference price. This would give them a stronger incentive to bid in a manner that reflects their costs.

Planning

Current NEM planning arrangements involve a mix of local and national perspectives and responsibilities. Having considered responses to the First Interim Report, the Commission considers that some key steps could be taken to enhance national coordination of transmission planning and investment to ensure that inter-regional considerations are more likely to be taken into account where potentially relevant.

In directing the AEMC to undertake the review, the MCE specified that the Commission should have regard to a number of principles previously agreed by the Council of Australian Governments (COAG). These are that:

- accountability for jurisdictional investment, operation and performance will remain with transmission network service providers (TNSPs);
- where possible, the new regime must be 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.

The Commission is of the view that the coordination of transmission planning and investment on a market-wide basis can be facilitated through leveraging the institutional structures that already exist in most regions of the NEM. AEMO, in exercising its functions as National Transmission Planner (NTP), has a national, strategic perspective that can provide a useful check on the local knowledge and responsibilities of TNSPs - and vice versa. Such a model is consistent with COAG's principle that ultimate accountability should remain with TNSPs.

The Commission's proposals therefore focus on enhancing the role of the NTP as the central element of a more integrated national transmission planning framework. It is proposed that AEMO as NTP should:

- have a greater role in reviewing transmission business planning reports and regulatory investment test processes;
- provide the demand forecasts used by transmission businesses in planning; and
- assume the Last Resort Planning Power from the AEMC.

The Commission has sought advice from AEMO on any additional functions or powers it believes are necessary for it to exercise this enhanced national role.

In addition, the Commission proposes that TNSPs should have a more clearly defined role in contributing to development of the NTP's national transmission network development plan. We also propose that TNSPs be formally obliged to consult with each other and the NTP in respect of investment needs that have cross regional solutions and impacts.

These enhancements would deliver the benefit of enhanced national coordination whilst maintaining the ownership and operation of transmission at the regional level. This approach makes best use of national perspectives and local knowledge, both critical for optimal decisions on transmission planning, investment decision making, procurement and operation.

The Commission notes however, that these additional NTP functions represent an oversight and coordination role which requires a body distinct from the first tier transmission investment decision maker. AEMO's exercise of this enhanced national transmission planning role would be inconsistent with its current Victorian jurisdictional investment decision making responsibilities.

The Commission's preferred solution would be for the Victorian jurisdictional investment decision making functions to move from AEMO to the TNSP, as specified by COAG and thereby creating a consistent approach across the NEM. This step would also have the effect of increasing the level of AER oversight of capital expenditure in Victoria.

The AER would also be able to obtain advice from an expert national transmission planning body independent of the investment decision-maker when conducting revenue determinations for all TNSPs.

Connections

Generators and large consumers seeking to connect directly to the transmission network are required to negotiate with monopoly transmission network service providers on key matters such as cost, timing and the connection standards. The Commission has considered carefully the extensive stakeholder comment on connection arrangements and notes the inherent challenges for both sides of these negotiations.

Although many connection applicants are companies of significant scale, there remain challenges in securing efficient and timely outcomes in negotiations with real asymmetries of incentive and information, potentially leading to overall costs being higher than they could be. Experiences of connecting generators that have made submissions to the Commission bear this out.

The Commission has carefully considered responses to the range of propositions for reforming the connections frameworks it outlined in the First Interim Report and has undertaken additional research and analysis. It proposes in this report a range of measures:

- An overhaul of the current rules provisions to remove ambiguity. The lack of clarity that is currently present in the rules makes it difficult for parties to negotiate efficient outcomes. We have set out a framework of principles to guide how the rules can be simplified which rationalises the categories of services defined in the rules and more clearly sets out the boundaries of these.

- Enhancing the negotiating process by mandating increased transparency of information for connection applicants by requiring publication of standard contracts and design standards by transmission businesses as well as provision of detailed cost information.

- Allowing connection applicants to share in the benefits of competitive provision of new assets built for the purposes of establishing a connection. We do not propose that connecting applicants should be allowed to build a substation on the shared network. Rather, we propose that the connecting party, which is paying for the connection, should have access to contractor bids and that the transmission business commissioning the work should consider the connecting party's preferences in final contractor selection.

- Clarifying through rules the responsibilities for provision of extensions of the transmission system beyond a substation to a generation facility or large consumer. A connecting applicant should have the option of requiring a transmission business to provide an extension as a negotiated transmission service. Alternatively, the applicant could provide the extension itself, with transmission businesses being able to tender for elements of this work.

Responding to this report

This review has been marked by a very high level of productive stakeholder engagement and we look forward to a continuation of that engagement in the final stages of the review. We welcome responses on the two access models outlined in this report but would urge respondents to avoid promoting adoption of elements of the optional firm access proposal in isolation from the balance of what is an integrated and interdependent package.

We note that the final product of this review will be a report with recommendations to the Standing Council on Energy and Resources who will consider and make policy decisions on those recommendations. They will also need to consider an appropriate approach for implementing any substantial framework changes adopted for the future development of the market.

Contents

1 Introduction and background to the review

1.1 Introduction

The Transmission Frameworks Review is a cornerstone review that touches on many of the arrangements influencing investment in, and operation and use of, the National Electricity Market (NEM). The effects of the introduction of various climate change policies, the global financial crisis and technological and demand pattern changes have demonstrated that the electricity market is not a static environment that operates in isolation. Rather, the arrangements that govern the operation of the NEM must be flexible and should drive efficient outcomes in whatever circumstances eventuate. This review provides the opportunity for the Commission to consider what arrangements are likely to deliver the most efficient outcomes over the long term, given the dynamic nature of the industry and, hence, future.

The First Interim Report for the review was published on 17 November 2011. That report set out for stakeholder consideration a series of potential paths forward for development of transmission arrangements in the NEM. These included:

- five alternative policy packages for providing generators with access to the transmission network;
- a range of options for enhancing the current planning arrangements, in addition to four options for more substantial reform; and
- three proposals for improving the economic regulation of the connection process.

This Second Interim Report narrows the access options down to two alternative and mutually exclusive paths. The "non-firm access" model essentially maintains the status quo, whereby access to the transmission network is dependent on generator bids and the amount of available network capacity. The "optional firm access" model introduces a fundamental change to the way in which generators and Transmission Network Service Providers (TNSPs) interact in the NEM by allowing generators to purchase financial access rights.[2] This report does not identify a preferred access model, but provides a qualitative assessment of the relative merits of each.[3]

The report also sets out the Commission's proposals for improving the planning and connections arrangements. The proposals for planning seek to drive greater coordination of transmission investment on a market-wide basis, while those for connections focus on strengthening the negotiating position of connecting parties through increasing the transparency of information.

2 The process for the physical dispatch of generating plant remains unchanged, however.

3 We are also currently undertaking quantitative analysis to provide further input into our assessment of the relative costs and benefits of the alternative models, but note that it is difficult to quantitatively assess the combined effects of such a fundamental package of reforms.

These proposals for connections and planning were developed in the context of the existing access model. However, both sets of proposals would also apply under the optional firm access model, albeit some modifications may be required. In particular, the optional firm access model would fundamentally shift the driver of much transmission investment away from decisions made by transmission planners to commercial agreements between generators and TNSPs.

Together, these options and proposals for reform are intended to provide a framework that will facilitate improved coordination of transmission and generation investment, and provide greater certainty, relative to the existing arrangements. This is consistent with the review's objective of minimising expected total system costs across transmission and generation, which should ultimately lead to lower prices for end consumers of electricity. This will occur where:[4]

- TNSPs have incentives to efficiently invest in and operate their networks to meet consumer requirements at least cost and support a competitive generation sector;
- generators have incentives to offer their energy at an efficient price and invest in new plant where and when it is efficient to do so;
- the policies, incentives and signals that govern transmission and generation decisions are coordinated to promote consistent decision making between the regulated and competitive sectors of the NEM; and
- the safety, reliability and security of the transmission system is maintained.

This review has focussed on the transmission arrangements that govern the interface between transmission and generation. This includes how generators can gain access to the wholesale market via the transmission system, the way in which congestion is managed, what charges generators face in relation to transmission, how the transmission network is planned, and how generators can connect to the transmission network. These arrangements - together with those for demand-side customers - are highly inter-related and so cannot be considered in isolation, hence the comprehensive and holistic nature of this review.

The Commission is seeking to identify the set of arrangements that is most likely to promote efficient investment and operational outcomes for generation and transmission over the long term. While the future is uncertain, the law, rules, financial obligations and institutions that provide the framework within which transmission in the NEM operates can provide a stable and predictable regulatory environment that supports efficient transmission and generation decisions, whatever the future relative prices of fuel sources, costs of generator technologies and locational costs turn out to be. This requires that any changes to transmission arrangements that result from our ultimate recommendations remain in place for a substantial period of time.

4 For further discussion on the assessment framework, see: AEMC, *Transmission Frameworks Review*, First Interim Report, 17 November 2011, Sydney, chapter 3.

1.2 MCE Terms of Reference

The Ministerial Council on Energy (MCE)[5] directed the Australian Energy Market Commission (AEMC) to conduct a review of the arrangements for the provision and utilisation of electricity transmission services and the implications of the market arrangements governing transmission investment in the NEM on 20 April 2010.

The Terms of Reference specifies that the 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 arrangements, particularly in light of the anticipated impacts of climate change policies and the potential impacts of extreme weather events.

The MCE noted that:[6]

> "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, we are 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 arrangements, which is particularly important given the inter-related nature of the issues involved and changes that may be developed.

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

1.3 National Electricity Objective and the MCE direction

The AEMC is required to have regard to the National Electricity Objective (NEO) in every review it undertakes under the National Electricity Law (NEL). The NEO will therefore form the overarching principle for the assessment framework used to evaluate potential transmission reforms.[7]

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5 The MCE was the forerunner to the current Standing Council on Energy and Resources.

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

7 Note that under section 88(2) of the NEL, the AEMC may give such weight to any aspect of the NEO as it considers appropriate, having regard to any relevant MCE Statement of Policy Principles.

The NEO is set out in section 7 of the 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 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 Terms of Reference specifies that the AEMC should have regard to the NEO and to certain principles previously agreed by the Council of Australian Governments (COAG) in relation to earlier reforms. These principles are:

- 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.

The Terms of Reference also provide that the AEMC is to have regard to the implications for trading and contracting risks and for investment and regulatory uncertainty, as well as the need for transitional and other arrangements to mitigate or manage such risks.

1.4 Policy context: related initiatives

The AEMC is considering this review in the context of a number of related initiatives. The two most relevant of these are highlighted below.

1.4.1 Economic regulation of network service providers rule change

In September and October 2011, the AER and a group of large energy users submitted a number of rule changes relating to network regulation. The rule change requests seek to change the way revenues are set for electricity and gas network service providers: principally how the size of the asset base used to provide network services and how the rate of return on capital are determined; and the process for making determinations.

In response to these requests, the Commission is currently developing draft rules based around the following principles:

- promote flexibility and adaptability, enabling the regulator to make decisions in changing circumstances, and for network service providers with different characteristics;
- improve the regulatory process to allow the regulator adequate time for decision making, to improve consumer engagement, and to improve transparency and accountability; and
- address ambiguities and clarify provisions, to put beyond doubt the interpretation of provisions, particularly in the National Electricity Rules.

A draft determination, including draft rules, is currently due to be published on 23 August 2012.

1.4.2 Power of choice review

The AEMC's Power of Choice review follows previous studies into Demand-side Participation (DSP) in electricity markets, which has seen some reforms over time to improve uptake of DSP in the NEM.

The purpose of the review is to identify opportunities for consumers to make informed choices about the way they use electricity. Consumers require information, education, incentives and technology to make efficient choices. Its aim is to also ensure that there are incentives for network operators, retailers and other parties to enable consumer choice and invest efficiently. The overall objective is to ensure that the community's demand for energy services is met by the lowest cost combination of demand and supply side options.

The key outcome for the review will be to recommend changes to the existing market and regulatory arrangements to ensure that cost effective demand side options are properly considered and correctly valued in both the planning and operation of the national electricity market.

We currently expect to release the Draft report for the review in early September 2012.

1.5 Submissions to the First Interim Report

Following publication of the First Interim Report, the Commission sought comments from stakeholders on five alternative pathways to reform that represented a range of possible approaches to structuring the law, rules, financial obligations and institutions that provide the framework within which transmission in the NEM operates. The report also set out for comment options for enhancing the planning and connection arrangements.

The Commission received submissions from 26 stakeholders, including market participants, consumer and large end-user groups, governments and market institutions. A full list of submissions can be found at www.aemc.gov.au.

1.5.1 Access packages

In respect of the proposed access packages, submissions can broadly be characterised as either supporting the existing arrangements or supporting substantial change.

Those stakeholders that supported the existing arrangements, particularly large government-owned generators in New South Wales and Queensland, considered that:

- in their view, none of the identified problems, including the risks associated with network congestion, are material; and
- introducing firm access rights for generators would create uncertainty and complexity.

Those that supported change, including other electricity market bodies and privately-owned generators based largely in Victoria, did so on the basis that:

- coordination between transmission and generation investment is not currently optimised; and
- congestion is, or will be, a material problem.

Amongst the stakeholders that advocated changing the access arrangements, many did not consider any of the packages alone would represent an appropriate way forward. Consequently, some stakeholders suggested models of their own that were broadly a combination of the congestion pricing mechanism proposed under package 2 and the regional optional firm access model, package 4.[8] They considered that, together, these packages would encourage cost reflective bidding, improve locational signals and improve coordination between transmission and generation investment decisions.

1.5.2 Planning

The Commission presented two sets of options for enhancing or reforming the planning arrangements. Of the suggested enhancements, a national framework for reliability standards, improving the consistency of TNSP Annual Planning Reports (APRs) and improving the transparency of the Regulatory Investment Test for Transmission (RIT-T) were almost universally supported. Responses to aligning TNSP revenue resets and introducing reliability standards for interconnectors were mixed.

Responses to the proposed options for greater reform were also mixed. Improving coordination of APRs and the National Transmission Network Development Plan

8 The models put forward by International Power GDF Suez, the Australian Energy Market Operator, the Australian Energy Regulator, the Major Energy Users and Loy Yang Marketing Management Company/AGL are discussed in appendix A.

(NTNDP) was generally viewed as beneficial, although some suggested that the benefits might be relatively limited.

Creating a consistent, harmonised planning regime based on the existing South Australian arrangements drew significant support from many stakeholders on the basis that it would promote efficient inter-regional investment through improved consistency of arrangements and the use of financial incentives would also encourage efficiency.

Although implementing the Victorian planner/procurer arrangements across the NEM was supported by the Victorian Department of Primary Industries (DPI), the Australian Energy Market Operator (AEMO) and some renewable generators, it was opposed by the majority of stakeholders. These stakeholders expressed concerns about a lack of accountability and oversight, an inefficient separation of responsibilities, and the lack of financial incentives.

Few supported the proposed joint venture model, although it was viewed by some as a potential long term goal.

1.5.3 Connections

The Commission also set out a number of proposals for improving the connection arrangements. Of those commenting, most stakeholders considered that the proposal to strengthen the negotiating framework would deliver the greatest benefits. Improving the dispute resolution framework was generally viewed as a complementary step that would be insufficient in its own right. There was limited support for treating connections as prescribed services on the basis that it would reduce flexibility, although this was supported by some renewable generators.

A number of stakeholders suggested that enhancing contestability in construction of the assets required to provide a connection would allow generators to better control costs and timeframes, although Grid Australia raised some concerns with the practicality of contestability. In relation to network extensions, there were divergent views regarding the way in these should be provided and whether third parties should be able to obtain access.

Finally, stakeholders generally agreed that the current connections regime would benefit from improved clarity, and that this would assist connection negotiations.

1.6 The review process

The table below sets out the process for this review.

Table 1.1 Review process

Document	Purpose
Issues Paper	To present the key issues identified by the Commission and set out the process for the review.
Directions Paper	To address some of the key issues raised in submissions to the Issues Paper and to identify key themes that the Commission proposes to take forward and how the Commission intends to do this.
First Interim Report	To identify and discuss a short list of potential internally consistent policy packages, explain the framework for the assessment of these and continue testing the materiality of the problems identified.
Second Interim Report	**To assess the packages identified in the First Interim Report and narrow these packages down to one or two preferred options.**
Final Report	To set out the Commission's policy conclusions and recommendations, and to note any high-level implementation and transitional issues for further consideration.

1.7 Where to from here

The Second Interim Report is the penultimate step before providing our final set of policy conclusions and recommendations to the Standing Council on Energy and Resources (SCER) by 31 March 2013.[9]

The AEMC is currently undertaking quantitative analysis to provide further input into our assessment of the relative costs and benefits of the alternative access models. We expect to publish the results of this modelling in late 2012. It is important to note that some costs and benefits are more suited to quantification than others. The ability to accurately model the combined effects of a complete package of reform is limited, and modelling the outcomes affected by long term dynamic decisions is particularly challenging. Therefore, qualitative assessment will continue to form a significant component of our evaluation.

A further key input to the Commission's analysis will be submissions received from stakeholders responding to this Second Interim Report. This review has been characterised by a high level of stakeholder engagement, which we hope will continue into this last stage of the review.

9 On 28 May 2012, the Chair of the SCER wrote to the AEMC extending the delivery date for the review's Final Report to 31 March 2013.

1.8 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 committee comprises representatives of AEMO, the Australian Energy Regulator (AER), industry participants and energy end-users.

Meetings of the Consultative Committee have been held on:

- 26 July 2010;
- 10 December 2010;
- 7 March 2011;
- 28 September 2011; and
- 18 April 2012.

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

1.9 Structure of this report

The remainder of this report is structured as follows:

- Chapter 2 sets out an overview of the non-firm access model, which is based on the existing arrangements that apply in practice where generators have a limited ability to manage the risk of not being dispatched.
- Chapter 3 provides an overview of the optional firm access model, which introduces a framework that allows generators to obtain greater certainty of access to their regional reference price. This is supported by a separate Technical Report prepared by AEMC staff that sets out the details of how the model would operate.
- Chapter 4 provides a comparative assessment of the two proposed access models described in the preceding chapters.
- Chapter 5 presents proposals for an enhanced framework for transmission planning and pricing.
- Chapter 6 sets out our proposals for clarifying and improving the connection arrangements.
- Appendix A discusses stakeholders' responses to the options for generator access set out in the First Interim Report and how these have informed development of the optional firm access model.

- Appendix B provides more detailed information underpinning our proposals for "extensions" to the transmission system as presented in chapter 6.

1.10 Responding to this report

The Commission welcomes submissions on this Second Interim Report.

How to make a submission

The closing date for submissions to this Second Interim Report is **10 October 2012**.

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

2 Overview of the non-firm access model

Box 2.1: Summary of this chapter

This chapter provides an overview of a model for transmission access that is based on the arrangements that exist in practice in the NEM today. Generators would have a right to connect *to* the network, but would not be able to obtain a firm right for use *of* the network. Instead, a generator's right to use the network would depend upon whether it was scheduled in the merit order and the presence of congestion on the network. Generators would receive no compensation if the network was not available for their use.

As is currently the case, generators would not pay a charge for using the network. Instead, the exposure of generators to the risks of congestion together with loss factors would provide signals of where to locate within a region.

Implementation costs for this model would be minimal, as it broadly reflects the existing approach to access as applied in practice.

2.1 Introduction

This chapter sets out the first of the two alternative models for transmission access that the Commission is considering. It is based on the status quo, and therefore represents the least change from existing frameworks. While this regime would not introduce any new features to the existing arrangements, it would provide clarity on the nature of access. This has been the source of some disagreement and confusion to date.

This chapter is structured as follows:

- section 2.2 describes the existing access arrangements in the NEM;
- section 2.3 sets out the key design features of the non-firm access model; and
- section 2.4 discusses the implementation of the model, focussing on the changes that would be made to the frameworks to clarify the nature of access provided to generators.

2.2 Current access arrangements

Currently, the NEM operates under what has been termed an "open access regime". Under these arrangements, generators have a right to connect *to* the transmission network,[10] but this right does not extend to a firm right of access *across* the network.

10 The National Electricity Rules provide a connection applicant with an enforceable right to connect to the network in accordance with the process under Chapter 5. A TNSP has a corresponding obligation to connect the connection applicant in accordance with the Chapter 5 process.

Instead, the access granted to generators for use of the network is dependent on their dispatch.

Box 2.2: The dispatch process

In order to sell energy into the wholesale market, generators submit offers to AEMO, the market operator. In addition to certain operational parameters, these offers detail the volume the generators are willing to generate at each of up to ten different prices. AEMO uses the offers to determine the most cost-effective way to meet the prevailing demand and frequency control requirements. Offers to generate are stacked in a "merit" order of rising price, and this merit order is then used by AEMO to dispatch generators, least cost first.

The point on the merit order at which demand is satisfied determines a single price for electricity in each region of the NEM: the Regional Reference Price (RRP). Generators within a region receive the RRP, adjusted to reflect losses on the transmission network, for the volume of generation for which they are dispatched.

However, at times there may be reasons why least cost generation cannot be dispatched, and this may result in more expensive generation being dispatched instead in order to ensure that demand in a particular area is satisfied.[11] The transmission network has physical limits that AEMO must take into account when determining dispatch, which are known as constraints. When more generation is offered in an area than AEMO can dispatch, because of these limits, generators may be “constrained off” – not dispatched for the full quantity they have offered, even where they have offered electricity at a price less than the RRP. Conversely, generators may be "constrained on" when dispatched for a quantity greater than that offered at the RRP.

Through the dispatch process, AEMO determines the least cost combination of generation that satisfies demand and which the transmission network can accommodate. Generators within a region receive the regional reference price (RRP) for the volume of generation for which they are dispatched.

When there is congestion (that is, a greater demand for use of part of the transmission network than can be accommodated), generators face the risk of not being dispatched. In such circumstances, the generator would be constrained off, and would not be able to use the transmission network.

A generator's "right" to use the transmission network therefore depends on whether it is dispatched and the availability of network capacity. Generators do not have any inherent right to be dispatched, nor do they have a right to be compensated when constrained off.

11 For example, the technical capacity of the transmission network, restrictions on how fast a generator can increase production, or it being optimal to withhold otherwise cheaper generation to access the generator's cheaper frequency control offers.

In this report, we term the level of service described above as "non-firm access". This is to differentiate it from the open access arrangements that govern access *to* the network.[12]

2.2.1 Stakeholder views

We note that, over the course of the review, some generators have disagreed with our characterisation of the current arrangements. In particular, in submissions to the First Interim Report, AGL and LYMMCo contended that generators currently have "protected access" with respect to new generator connections (although "non-firm" access for other causes of congestion, such as network maintenance and outages). They suggested that this position is supported by a number of factors, including Use of System Agreements originally put in place between the Victorian Power Exchange and Generation Victoria,[13] as well as the intent and drafting of the National Electricity Rules (NER).[14]

The NER do contemplate, in clause 5.4A, a mechanism through which TNSPs could offer generators a superior service to non-firm access. However, we are not aware that these provisions have ever been used and, for the reasons explained in section 2.4, we have concluded that they are unlikely to be workable in practice. We are also not aware of the existence of any other mechanism that applies in practice to provide generators with "protected access", as described above.

We therefore consider that our characterisation of the access arrangements in the NEM is an accurate description of the regime that applies in practice. The optional firm access model presented in the next chapter provides a workable model of firm access rights that draws from the apparent intention of clause 5.4A. This demonstrates that significant changes would have to be made to transmission frameworks to give effect to a level of service other than universal non-firm access.

2.3 Key features of the non-firm access model

This section sets out the main features of the non-firm access (NFA) model. However, given that the model largely reflects the arrangements that apply in practice today, the discussion is relatively brief.[15]

2.3.1 Access determined by dispatch and network availability

Under the NFA model, a generator's "right" to use the network would be determined by whether it is scheduled in the merit order and therefore dispatched.

12 Access *to* the network would still be provided on an open basis even if a firm product for use of the network was made available.

13 The Commission has not been provided with copies of these agreements.

14 AGL, First Interim Report submission, pp. 3-5; LYMMCo, First Interim Report submission, pp. 3-5.

15 For a fuller description of the existing arrangements, see chapter 4 of the First Interim Report.

Where constraints arose, generators might not be able to be dispatched in accordance with the merit order. In these circumstances, a generator may be constrained off (or on) the network. Generators would not be entitled to any form of compensation for the loss of margin arising from not being dispatched when they otherwise would have been, if not for the congestion.[16]

Access would therefore be determined by the merit order and by network availability. All generators that were dispatched would receive the RRP. Those "in merit" but unable to be dispatched, would receive no compensation.

Generators would therefore not face any price (or "basis") risk when trading within a region, because a single price would be determined and applied across the region. However, uncertain and unpredictable network congestion would lead to "dispatch risk" for generators, whereby they would face a risk of not being dispatched even when in merit. Generators would have limited ability to manage this risk, generally being reliant on the amount of network capacity provided by TNSPs' planning processes.

2.3.2 Charging and locational signals

The NFA model would not include any charge for generators for use of the transmission network. This means that generators would not be directly exposed to any costs they impose in terms of investment in the shared network (as opposed to investment in assets to connect generators *to* the network).[17]

However, there are a number of other signals that would be maintained which would inform generators' decisions as to where to locate on the network. These include:

- **Congestion**. A generator locating in an area with existing, or forecast future, congestion would risk being constrained off the network. This risk therefore provides a disincentive to locate in congested parts of the network.
- **Locational transmission losses**. Losses provide a signal of the short run marginal cost of transporting electricity, by reflecting the costs associated with lost energy, which will vary by location. This may form a strong locational signal, but the primary aim is to facilitate the efficient dispatch of generation, and not to signal any longer term costs associated with transmission investment.
- **Inter-regional price differences**. Price differences between regions provide a signal of the region in which a generator might locate. However, the absence of intra-regional price differences means that there is no such signal within a region.

In a non-firm regime, dispatch risk therefore plays an important role as an intra-regional locational signal.

16 Generators may still be entitled to compensation where they are affected as a result of an AEMO intervention. See clause 3.12.2 of the NER for further details.

17 The cost of connecting to the network provides generators with a locational signal in respect of their proximity to the network, but not between different locations on the network.

It is, however, an imperfect signal in that forecasting future congestion is difficult. In addition, generators may still locate in congested areas where the expected returns are higher[18] than the expected returns associated with locating in an uncongested part of the network. Such decisions will impact on the access available to other generators.[19]

2.3.3 Network augmentation and planning

Under the NFA model, generators would be able to fund augmentation of the shared transmission network in order to reduce congestion and therefore the dispatch risk they face. However, such generators would receive no exclusive "right" to the use of such augmentations, and the benefit of the reinforcement may accrue to other generators, either initially or over time.

As is currently the case, TNSPs would have obligations to meet reliability standards governing the service they provide to load. Demand growth may therefore prompt TNSPs to augment the capacity of the transmission network. This would be likely to benefit generators located closest to major load centres.

TNSPs are required to assess any potential network augmentations through use of the Regulatory Investment Test for Transmission (RIT-T). This test requires TNSPs to examine the costs and benefits of credible options to establish the one that maximises net market benefits. Where investment is being undertaken to meet reliability standards, the preferred option may have a negative net economic benefit, in which case the RIT-T should identify the option which minimises these costs.

The RIT-T process does contemplate that a network augmentation might be justified solely to improve the service provided to a particular generator, for instance if it had significantly lower fuel costs than the generation it would displace as a result. However, identifying different generation costs can be difficult,[20] and we understand that few intra-regional network augmentations have been justified on the basis of market benefits without a reliability driver.

In addition, the market benefits captured by the RIT-T do not include the value to generators of increased certainty of dispatch. Even if the RIT-T was amended to include this, it is unclear how it would be robustly measured.

There should therefore be no expectation in a non-firm access regime that all congestion will necessarily be "built out". Some level of congestion is likely to be a feature of efficient markets and, in the non-firm model, generators would not be able to influence the extent to which congestion affecting them was addressed. Nevertheless, it would be important that the network planning arrangements were as effective as possible. Chapter 5 discusses our proposals that aim to promote this.

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18 For instance, as a result of superior wind resources.

19 For a demonstration of this, see appendix C of the First Interim Report.

20 Especially between gas-fired generators.

2.4 Implementation of the non-firm access model

Implementing the NFA model would be relatively straightforward, in that it represents the arrangements that currently apply in practice. The main change would be to clarify in the rules that generators would not have any right to negotiate with TNSPs to obtain anything other than the default, non-firm service for network use: that service which, in practice, currently applies to all generators.

The way in which the rules could be clarified is discussed further in chapter 6. This section provides our rationale for why this change should be made.

2.4.1 Clause 5.4A

The existing rules, predominately through certain provisions of clause 5.4A, appear to contemplate generators negotiating firm transmission network user access with TNSPs. This would take the form of negotiating compensation from a TNSP in the event that the generator is constrained off the network, in return for an access charge.[21] However, we consider that these provisions cannot work in practice because the scheme is not mandatory and all generators have free, unfettered use of the network (when it is available).

If a TNSP was to negotiate firm access with a generator in return for an access charge, it would have two options:

1. augment the network to provide sufficient capacity for that generator to always be dispatched; or

2. pay compensation to the generator in the event that it was constrained off.

Under the existing access regime, the first of these is not practical. The TNSP could not prevent other generators from connecting to the network and using capacity. Assuming that the new entrant generators did not opt into the scheme, the TNSP would have no additional funding, other than the access charges paid by the firm generator, in order to further augment the network.[22] Thus, network augmentations to maintain access could not be funded unless such augmentations passed the RIT-T.[23]

The second option is also not practical. Paying compensation would require a counter-party to provide the necessary funding. However, the rules do not provide clarity on where the funding for the compensation would come from.

The rules appear to contemplate TNSPs recovering charges from another generator in the event that dispatch of that generator results in a firm generator being constrained

21 NER clauses 5.4A(b), (f) and (h)(1).

22 Assuming that the augmentation would not pass the RIT-T, either for the purpose of meeting load reliability standards or as a market benefit augmentation.

23 Unless investment falls within the exceptions in clause 5.6.5C(1) to (9).

off.[24] However, there is no mechanism to compel generators to opt into this scheme and generators that cause others to be constrained off are unlikely to have incentives to join.[25]

Further, the rules require TNSPs to negotiate in confidence and so TNSPs must negotiate compensation arrangements with one generator at a time. Thus, if a TNSP agreed to pay compensation where a generator was constrained off, it could never be sure that it would be able to recover the funds from anyone other than the party with which it was negotiating. The TNSP would either have to risk reopening negotiations with incumbents or take the risk that arrangements could be negotiated with future generators.

In summary, the firm access provisions contemplated in the rules cannot work in practice and, as far as we are aware, have not been applied to date. For this reason, the First Interim Report set out our conclusion that either these compensation provisions should be removed to clarify the non-firm nature of the access regime, or that they should be replaced with a workable form of access.

2.4.2 Stakeholder views

In response to the First Interim Report, a number of stakeholders supported the removal of clause 5.4A, commenting that removing the relevant rules provisions would usefully clarify the non-firm nature of the access regime that applies.[26]

However, other stakeholders considered that all or part of clause 5.4A should be retained in the rules. Hydro Tasmania stated that it "strongly believes that clause 5.4A should remain in the NER". It explained that "whilst it has not used clause 5.4A to negotiate firm access to the network or to be compensated if access is unavailable, Hydro Tasmania has used this clause as a lever to negotiate incentive arrangements with a TNSP".[27] It is not clear from its submission how Hydro Tasmania achieved this.

Similarly, Pacific Hydro submitted that although "rule 5.4A has not been implemented in full", "it is one of the few rules that enable a generator to endeavour to keep a TNSP to account for connections that can impact others". It further suggested that "removal of this rule and associated case-history would be detrimental to the outcomes for generators and - by extension via the cost pass through to consumers". Pacific Hydro appeared concerned that TNSPs "try to avoid" specifying a power transfer capability across the network.[28]

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24 NER clause 5.4A(h)(2).

25 Generators that cause others to be constrained off are, by definition, being dispatched themselves. This implies that they have no incentive to be part of a scheme that would require them to: (a) pay charges for access that they already have; and (b) pay compensation to those generators that they constrain off.

26 InterGen, First Interim Report submission, p. 2; Grid Australia, First Interim Report submission, p. 17; Infigen, First Interim Report submission, p. 2.

27 Hydro Tasmania, First Interim Report submission, p. 1.

28 Pacific Hydro, First Interim Report submission, p. 6.

Finally, the Clean Energy Council noted that, although it agreed with the Commission's position, "clause 5.4A also contains other aspects relating to the negotiation process", including "the provision of information and negotiations in good faith". It suggested that "removal of these components of clause 5.4A will present a significant barrier to achieving a reasonable outcome for new generators connecting in the NEM during negotiations with TNSPs".[29]

2.4.3 Commission conclusions

As set out above, the Commission continues to consider that, were it to recommend the non-firm regime as its preferred option for generator access, this should be implemented through clarifying the relevant sections of the rules. Retention of provisions in the rules that cannot work, and that are inconsistent with the overarching access arrangements, would unnecessarily frustrate and delay negotiations. This would be likely to increase costs to generators and, ultimately therefore, to consumers.

We note Hydro Tasmania's view that clause 5.4A can be used as a lever to negotiate certain outcomes with TNSPs other than firm access (or compensation for the absence of access). However, if these outcomes are seen as desirable, we request that stakeholders explicitly identify them so that specific mechanisms to achieve them can be developed and evaluated. Placing unreasonable and unworkable obligations on TNSPs in order to achieve a result which is different to the stated intent of the obligation would represent poor regulatory practice.

We agree with the Clean Energy Council that it would be important for provisions to be retained in the rules requiring that negotiations for the *connection* of generators be undertaken in good faith and appropriate information provided.

However, it is important to be clear that, under the non-firm access regime, it would not be economic for TNSPs to provide generators with a guaranteed power transfer capability *across* the network. We consider that to facilitate this would require significant alterations to be made to existing transmission frameworks. While the Commission has yet to decide whether or not this would be appropriate, the next chapter sets out our preferred model for giving effect to such changes.

29 Clean Energy Council, First Interim Report submission, p. 8.

3 Overview of the optional firm access model

Box 3.1: Summary of this chapter

This chapter sets out a model for transmission access that provides generators with the option of obtaining financially firm access to their regional reference price. Generators and retailers could also obtain firm inter-regional access rights to hedge the difference between two regional reference prices. The mechanism to deliver this access would be a combination of: physical network augmentation, as specified by a firm access planning and operating standard; and settlement payments from non-firm to firm generators, where the former prevent the latter from being dispatched.

This model would provide firm access to generators who are prepared to pay the associated charge. As generators would be making the economic trade-off between the benefits and costs of firm access, there would be no need for TNSPs or the regulatory planning process to estimate the value that generators place on the firm access. The model would also largely address the problem of disorderly bidding, where generators offer electricity at non-cost-reflective levels and which can result in inefficient dispatch.

The model would introduce new costs for non-firm generators, who would be liable to pay compensation to firm generators in the event of congestion, but who would be assured of receiving at least their offer price.

The optional firm access model would require fundamental changes to the NEM, and this would represent a very significant implementation task.

3.1 Introduction

This chapter sets out a model for transmission access that provides generators with the option of obtaining financially firm access to their regional reference price.[30] It builds on the second and fourth packages of policy reforms that we presented in the First Interim Report. Having considered the large number of submissions received in response to our last report, the Commission believes this model to be the best alternative to the arrangements presented in the previous chapter.[31]

The remainder of this chapter is structured as follows:

- section 3.1 describes the objectives and summarises key features of the model;
- sections 3.2 to 3.8 describe the key features of optional firm access;

30 See Box 3.2 for a further explanation of "firm access" and circumstances in which it would not be fully firm.

31 For the reasons why the Commission has decided not to proceed with the other reform packages from the First Interim Report, please see appendix A of this report.

- section 3.9 describes a model for inter-regional access; and
- section 3.10 highlights some of the challenges that would be associated with implementing the model, should it be recommended.

The chapter gives a high level overview of how the model would work. It is necessarily simplified. A more detailed description of the model is provided in the Technical Report prepared by AEMC staff, which also provides the reasoning for the selection of particular design options. Interested parties are encouraged to refer to that report in order to gain a full understanding of the model and to inform their submissions.

3.2 Overview

3.2.1 Objectives

The Optional Firm Access (OFA) model aims to address the most significant concerns with the interface between transmission and generation. The previous chapter identified the following issues with the current arrangements:

- the lack of certainty of dispatch faced by generators when there is congestion, compounded by the inability of generators to obtain firm access, even where they fund augmentations of the transmission network; and
- the lack of clear and cost-reflective locational signals for generators, such that their locational decisions do not take into account the resulting transmission costs.

The lack of short-term and long-term intra-regional locational signals under the current regime results in:

- incentives for generators to offer electricity in a non-cost reflective manner in the presence of congestion; and
- the planning of transmission networks not being co-optimised to minimise the combined costs of generation and transmission.

The Commission has also previously identified a further concern:[32]

- the importance of TNSPs' operating their networks to maximise availability when it is most valuable, and the challenge they face in doing so given their lack of exposure to the financial costs of reductions in capacity.

In addition, the model would improve the ability of market participants to manage the risk of price differences between different regions of the NEM, which should encourage a higher level of contracting between generators and retailers in different regions.

32 See section 5.2.5 of the First Interim Report for further discussion.

Box 3.2: What is firm access?

A generator's primary concern is earning revenue. This is currently achieved by being dispatched, subject to constraints and the bids of other generators, and receiving the spot price in return. This provides backing for forward (derivative) contracts sold to retailers. When generators raise concerns that they are not getting "access" to the market, their fundamental concern is that they are not earning revenue.

Consequently, we can think of *access* as *being paid at the regional reference price*.[33] In the optional firm access model presented in this chapter, a firm generator may be paid even if it is not dispatched because of network congestion. This is referred to as "financial access" and delinks (financial) access from (physical) dispatch. However, even financial access must be underpinned by physical network capability to provide sufficient revenue from non-firm generators to compensate firm generators where they are constrained off. Therefore, sufficient network capability must be provided to meet aggregate demand for firm access.

By decoupling access from physical dispatch, access can be reallocated on a different basis, with priority given to firm generators – those generators who pay for a firm access service from their local TNSP. Firm generators would enjoy greater financial certainty than they do now; non-firm generators would receive less certainty.

Although network capability may be planned to meet aggregate demand for firm access, there may be operating conditions under which the capacity of the transmission network is reduced and access for firm generators must correspondingly reduce. Consequently, even "firm" generators will only ever achieve firm financial, and not fixed financial or physical, access.

The scope of the OFA model makes it more complex than alternative models with a more limited scope (e.g. shared access congestion pricing, the second package of reforms from the First Interim Report). However, an all-encompassing model such as this is in some sense simpler to implement than introducing a patchwork of changes, which might also risk creating unintended consequences.

In the event that no generator held firm access rights, the arrangements would operate in the same manner as the current regime, with the addition of a congestion management mechanism (similar to that presented in the second package of reforms from the First Interim Report).[34]

The optionality in the model creates complexity and requires careful and robust design to ensure dysfunctional behaviour is not encouraged. However, the Commission believes that this is preferable to an alternative of no optionality (i.e. generator reliability standards, the third package of reforms from the First Interim Report).

33 Ignoring losses.

34 See access settlement in section 3.5.

In this context, the OFA model addresses several difficult and longstanding transmission issues in the NEM.

3.2.2 Features

The previous chapter identified that, under the current arrangements for transmission, there is a lack of certainty of access faced by generators. In the present NEM design, the market provides access to generators by allowing them to be dispatched and so sell their output at the regional reference price (RRP). During periods of intra-regional congestion, a generator's level of access is uncertain, dependent on the level of congestion and the dispatch offers of other nearby generators. It may be constrained off – unable to obtain the access it desires.

The OFA model gives generators the option of obtaining firm access to their regional reference price. Even when they were not dispatched because of congestion, firm generators would still be paid. The key features of the model are illustrated in Figure 3.1 and may be summarised as follows:

- *Access procurement*. Generators would have the option of agreeing a quantity of firm access with their TNSP, which may be for all or part of their output. Generators that do not procure firm access would receive non-firm access.[35]

- *Firm access standard*. TNSPs would be required to plan and operate the network to provide the level of capacity necessary to meet the agreed quantities of firm access. TNSPs would not be required to plan or operate the network to provide non-firm access. TNSPs would still be required to meet their jurisdictional reliability standards for load.

- *Access settlement*. Where dispatch of non-firm generators contributed to congestion they would compensate firm generators for any loss of dispatch.[36] This would aim to ensure that firm generators were in the financial position they would have enjoyed had they not been constrained off – that is, financial certainty would be enhanced. Access settlement would occur automatically through the AEMO's settlement process. The processes for dispatch and regional pricing would not be changed, although the incentives for generators to offer their output at non-cost reflective prices (a practice known as disorderly bidding) would be reduced. These behavioural outcomes, which mean the optional firm access model also behaves as a congestion management tool, are discussed in chapter 4 of this report.

- *Access pricing*. Generators would pay TNSPs to obtain firm access. There would be no charge for non-firm access, although non-firm generators would be

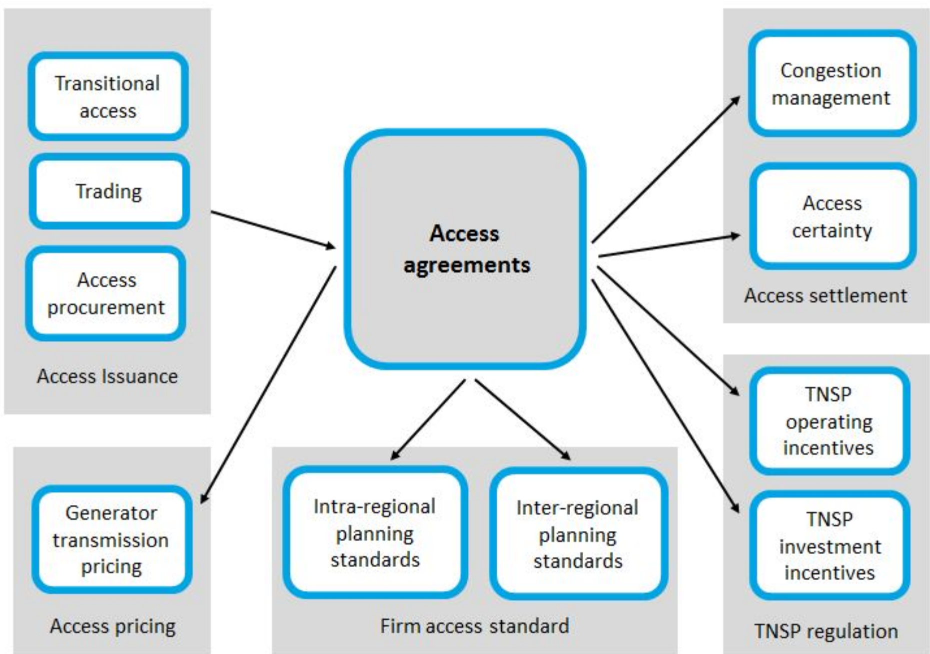
35 Generators could be part-firm – agreeing an access amount that is less than their generating capacity, and receiving non-firm access for any output in excess of the agreed access amount.

36 Although generators would have the option of being firm or non-firm, participation in the model would be mandatory, thereby addressing the issues with providing firm access where participation is optional (see discussion in section 6.1.1 of the First Interim Report).

required to compensate firm generators they constrained through access settlement. A request for additional firm access by a generator would increase the network capacity that the TNSP is required to provide over time, imposing new costs on the TNSP. The firm generator would pay an amount to the TNSP that covered these incremental costs. The purpose of access pricing is to estimate what these costs are.

- *TNSP regulation*. TNSPs would be monopoly providers of the firm access service, which would be treated as a prescribed service. TNSPs would be subject to regulation in four areas: issuance, pricing, revenue and quality.
- *Transition*. Transition processes would aim to mitigate any sudden changes that might arise from the introduction of a new access model. Affected parties should have time to develop their capabilities for operating in the new regime without being exposed to undue risks. The main transition mechanism would be the allocation of transitional access to existing generators. These generators should receive a level of firm access that takes into account historical levels of effective access. However, transitional firm access would be sculpted back over time and would then expire. No access charges would apply to transitional access.
- *Inter-regional access*. Generators and retailers would be able to procure firm inter-regional access rights which would entitle them to the price difference between two regions on their access amount. Their purchase of firm inter-regional access would guide and fund the expansion of interconnectors.

Figure 3.1 Key features of the optional firm access model



The next seven sections of this chapter discuss these features in greater detail.

3.3 Access procurement

Through the procurement process, a generator could procure new or additional firm access service, by entering into an access agreement with the TNSP in its region (the local TNSP). The generator would seek the combination of firm access amount, location and duration that best met its needs and for which it was prepared to pay the associated firm access charge.[37] Default firm access service terms and prices would be regulated. Primarily, the procurement process would involve information exchange rather than commercial negotiation.[38]

There would be no obligation on generators to procure firm access. Generators who did not do so would receive, instead, a non-firm access service for which they would not pay the TNSP. They may, however, be required to compensate firm generators through access settlement.[39]

The access agreement would specify the firm access charge and service parameters, such as the firm access amount, its term and whether the agreed amount would vary between peak and off-peak times.[40] TNSPs would be permitted to reasonably delay firm access commencement to give time for necessary network expansion. The agreement may also include some standard terms such as prudential requirements, termination and assignment.[41] However, most terms of service – such as service standard and liability – would lie outside the agreement, in the rules and associated regulatory instruments.

The procurement process would typically be iterative, with the generator submitting a request, the request being priced and the generator then amending its request in response. However, the role of the TNSP would not simply be to provide a price for each request made,[42] but also to advise the generator on possible service parameters that might best meet the generator's needs. For instance, TNSPs should advise generators how different access locations or firm access amounts would affect the

37 See access pricing below in section 3.6.

38 In principle, it may be desirable that service parameters could be customised by mutual agreement, to the extent that this did not adversely affect other transmission users (other than non-firm generators). For further discussion see section 7.3.5 of the Technical Report. However, customisation would create complexity; the degree of customisation permitted would need to be determined in later stages of the project.

39 Non-firm generators would never receive less than their offer price – see access settlement in section 3.5.

40 This would allow generators to match their access requirements to their forward energy contracts.

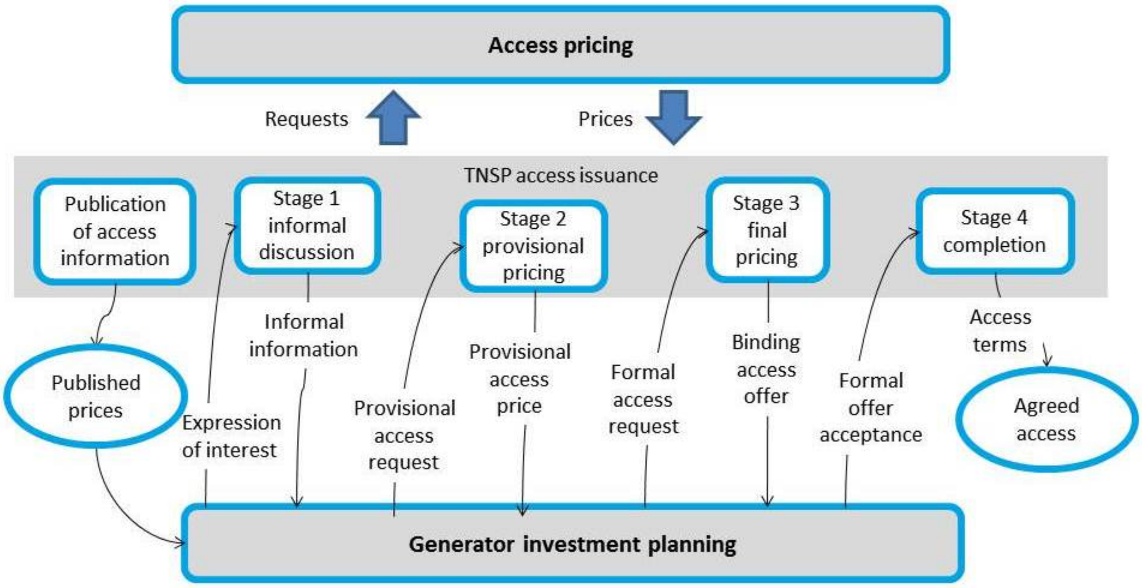
41 Prudential requirements would be significant, reflecting generators' financial commitments for the length of their access agreements. Further consideration would need to be given to how they would be structured.

42 Further consideration should be given to which body should perform the pricing. While there may be benefits in TNSPs performing the role through a streamlined procurement process, there would also be benefits in AEMO performing the role in consultation with TNSPs for consistency with the treatment of load charges and to cater to situations where two TNSPs may be involved. Please refer to the discussion of transmission pricing and TUOS charging in section 5.6.

access charge, and where small changes in the firm access amount triggered a large incremental cost.

Access pricing and procurement interact, since prices depend upon existing and prospective access agreements. Therefore, each access request or agreement may affect the pricing of other, concurrent requests. The procurement process would need to be structured to manage these interactions so as to avoid placing undue risk and uncertainty on generators or TNSPs. A possible process is illustrated in Figure 3.2.

Figure 3.2 Access procurement process



Generators would be able to withdraw from the procurement process at any stage until the agreement was finalised. They would be liable for the costs incurred by the TNSP in providing information and prices. TNSPs would be required to provide information in a timely fashion, and in good faith.

Stage 1 access requests would be confidential. Progress in later stages would be published to ensure transparency of the queuing and pricing processes. Once agreed, service parameters would be published. Whether details of access charges, payment arrangements and any customisations of service parameters were published would need to be considered.

Generators would be able to trade firm access rights. Rather than procuring additional firm access from a TNSP, a generator could instead purchase that amount of access from a generator which was located in a similar part of the network.[43] TNSPs would be required to approve the trade, to ensure that the TNSP would be able to provide the amended access, and to amend its access agreements to reflect the trade.

43 The trading parties would require similar access to the constrained parts of the network, such that they have similar participation in the flowgates which form the basis for access settlement – see access settlement in section 3.5.

3.4 Firm access standard

The quality (the firmness and reliability) of the firm access service would depend on the capacity and reliability of the shared transmission network that underpins it. Two features of the model should provide generators with confidence that service quality will be maintained:

1. a *service standard* that specifies the minimum service quality that must be provided to *each user*; and

2. a corresponding *network standard* that specifies the minimum level of transmission capacity that the TNSP must build and maintain to provide, concurrently, the minimum service quality to *all users* in aggregate under a given set of operating conditions.[44]

The *firm access standard* – in combination with the set of all access agreements – performs both of these roles. In planning and operating its network, a TNSP must therefore ensure that it met the firm access standard as well as maintaining existing demand-side reliability standards, which would still apply alongside the OFA model.

The firm access standard would take no account of non-firm generators, who would therefore expect to receive an inferior level of access firmness.

Even for firm generators, access would be *firm* but not *fixed*. The firm access standard would progressively scale back the service level that must be provided under more severe transmission conditions and so would represent a service profile that could realistically be provided by a transmission network. The *agreed access amount* specified in each access agreement would be a nominal amount and would not be required to be provided in every single settlement period in which the agreement was active. Rather, a minimum amount of access must be provided which would be a specified percentage of the nominal amount. The percentage, or *firm access standard scaling factor*, would vary according to transmission conditions prevailing in the particular period. Possible scaling factors are illustrated in Table 3.1.

44 A TNSP must ensure that it could provide the level of service defined by the firm access standard to every firm generator concurrently, since it is possible that every generator would require access at the same time.

Table 3.1 Illustrative firm access standard scaling under different operating conditions

Operating condition tier	Description	Example scaling factor
Normal operating condition tier 1 (NOC1)	System normal	100%
Normal operating condition tier 2 (NOC2)	Minor change from system normal	90%
Normal operating condition tier 3 (NOC3)	Moderate change from system normal	80%
Normal operating condition tier 4 (NOC4)	Major change from system normal	50%
Abnormal operating conditions	Severe change from system normal	0%

The firm access standard defined in Table 3.1 above is indicative only. In an actual firm access standard, the descriptions of the different operating condition tiers would be defined exactly and explicitly. Defining an actual firm access standard would be undertaken during OFA implementation and would involve TNSPs, AEMO and generators. In defining the normal operating condition tiers it is important that:

- they are *clearly defined*, such that the correct tier can be unambiguously identified within settlement timescales;[45]
- they do not encourage *perverse* TNSP behaviour: for example, taking a line out so that its firm access standard obligation is reduced; and
- they are *relevant* to generators: for example, if generators are most concerned about congestion during planned outages, these must be covered by a normal operating condition tier which gives a relatively high access level.

A single firm access standard would apply to all firm access on the shared network. It would not be feasible to have different standards for different access agreements. However, a generator could choose the effective firmness of access that it preferred by agreeing an access amount that was higher or lower than its generating capacity, and paying correspondingly higher or lower access charges:

- A generator would be *part-firm* if it agreed an access amount that was lower than its generating capacity.[46]
- A generator would be *super-firm* if it agreed an access amount that was higher than its generating capacity.

45 This is to allow TNSP incentive payments to be cleared through AEMO settlement - see TNSP regulation in section 3.7.

46 Discussion of generating capacity in this section refers to a generator's sent-out capacity.

Table 3.2 shows the different effective service levels that a 1000MW generator could obtain by procuring different amounts of access.[47] It can be seen that the super-firm generator receives 100 per cent access under both tiers of normal operating conditions. However, it never receives a level of access that is higher than its generating capacity.

Table 3.2 Effective service levels for a 1000MW generator

Effective service level	Agreed amount	NOC1 access	NOC2 access
Firm	1000MW	1000MW	900MW
Part-firm	800MW	800MW	720MW
Super-firm	1111MW	1000MW	1000MW

Note: The same firm access standard scaling factors are applied as set out in Table 3.1. NOC1and NOC2 access refer to the levels of access that must be provided under normal operating conditions tiers 1 and 2.

The result of a generator's willingness to pay higher access charges to be super-firm would be a higher level of network redundancy in those parts of the network that were critical to that generator's access. It would not be practical or efficient to plan the entire network to provide a fixed access service, which did not vary with transmission conditions. Instead individual generators would make commercial decisions on the most appropriate trade-off between transmission costs and effective service level, thereby guiding network development.

In summary, the firm access standard provides the nexus between access agreements and other transmission processes such as network planning and operations, access pricing, and TNSP incentive regulation. A TNSP would have to ensure that, in real time, it always has sufficient available transmission capacity to provide at least the minimum level of access that the firm access standard specifies. That obligation drives operational decisions and also, through the TNSP forecasting future access demand, drives planning decisions.

3.5 Access settlement

Access settlement is the process through which financial compensation would be provided to firm generators that were constrained off and so not dispatched.

The cost of providing the financial compensation would be recovered from the non-firm generators whose dispatch, by contributing to congestion, was causing the firm generators not to be dispatched. Access settlement would occur around congested *flowgates*: bottlenecks in the transmission network which are represented by binding transmission constraints in the NEM dispatch engine (NEMDE). Typically, there are no more than a handful of congested flowgates in a region in any particular settlement

47 The super-firm generator would impose a requirement on the TNSP to provide an additional 100MW network capacity during NOC2 conditions over what it would provide to the firm generator. Access charges would accordingly be higher.

period, so access settlement, whilst conceptually complex, should be straightforward to implement.

Two factors would need to be calculated in order to determine settlement payments: a generator's *use* of a flowgate and its *entitlement* to that flowgate. Its use would depend on its output and how much it contributed to the constraint. Its entitlement would depend on its agreed access level, its offered availability and the prevailing network conditions.[48]

A generator may require entitlements on several flowgates in order to achieve its agreed level of access. Access settlement would automatically translate the generator's agreed access amount into an entitlement on each relevant flowgate, which would depend on how energy flows on the network.

The allocation of entitlements would aim to give firm generators a target entitlement corresponding to their agreed access amount on each flowgate. However, when flowgate capacity was less than was required to meet aggregate agreed access levels (for example, during transmission outages), this might not be possible. Consequently, entitlements might be scaled back. The scaling process would mean that super-firm generators were scaled back slightly less than firm generators, while no entitlements would be provided to non-firm generators. On the other hand, when flowgate capacity was high, it might be possible to give full entitlements to firm generators and also give some entitlements to non-firm generators.

Where a generator's actual use exceeded its entitlement it would be required to pay compensation. Conversely, where a generator's entitlement exceeded it usage it would receive compensation. Typically, dispatched non-firm generators would compensate constrained-off firm generators. Aggregate compensation paid out would always equal aggregate compensation received.

The amount of compensation paid or received would be the difference between a generator's usage and its entitlement, multiplied by the *flowgate price*. The flowgate price is a measure of the value that is gained by relaxing the underlying constraint by a small amount. It is measured by the reduction in the total cost of generation dispatch when 1MW additional energy is able to pass through the flowgate. Where a constraint prevents cheaper generation from being dispatched, such that demand must be met by more expensive generation from elsewhere in the region, then the flowgate price will be high.

Note that generators that were required to pay compensation would always earn at least their offer price on each unit of energy for which they were dispatched. Therefore a generator should never regret being dispatched. A simple numerical example of access settlement is illustrated in Box 3.3.

48 A generator's entitlement would be based on the lesser of its offered availability and its agreed access level. That is, where the generator was subject to a power station outage, it would not receive access entitlements.

Another feature of access settlement is that it functions as a congestion management tool, even when no generators have firm access. Entitlements to a flowgate used only by non-firm generators would be allocated on the basis of offered availability. The compensation paid (or received) by each generator would be based on the difference between its entitlement and usage of the flowgate.

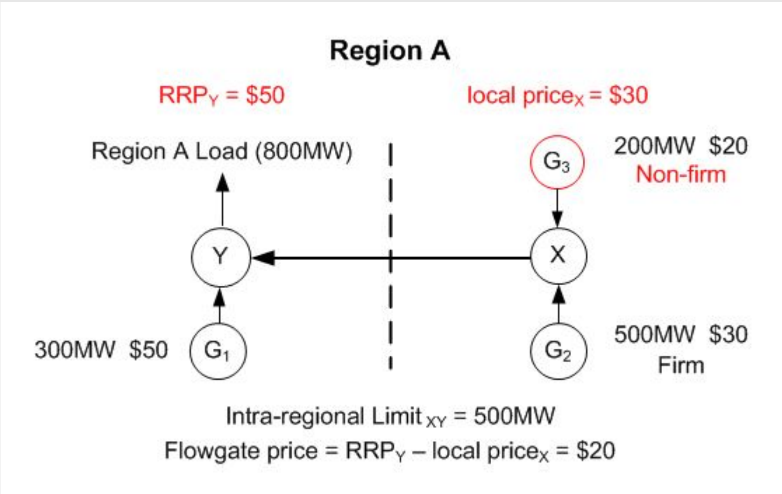
In summary, access settlement undertakes two main tasks. Firstly, it rations access to congested flowgates, giving preferential financial access to firm generators. Secondly, it provides financial compensation to generators dispatched below their (scaled) access levels and recovers the cost of this from generators dispatched above their (scaled) access levels.

Access settlement is conceptually complex, but it would be practically straightforward for two reasons. Firstly, all of the information required to calculate settlement amounts is either already present in the existing dispatch process (eg the flowgate formulations and prices) or would be specified in the access agreements (eg agreed access amounts). Secondly, the nature of transmission congestion is that only a handful of flowgates are likely to be congested at a time in each region. Therefore, the settlement algorithm would never be computationally onerous, and the verification and analysis of settlement statements by generators would be relatively straightforward.[49]

Box 3.3: Example of access settlement

Figure 3.3 illustrates a region with two nodes: X and Y. The regional demand of 800MW is located at node Y. There are three generators: G1 and G2 are located at node X and G3 is located at node Y. The network limit between X and Y is 500MW. The dashed line indicates a flowgate.

Figure 3.3



G2 has 500MW firm access. G3 is non-firm. G1 does not participate in the

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49 Generator traders should typically be aware of transmission constraints and their impacts on dispatch.

flowgate: it has no need for access to the flowgate capacity.

G2 offers 500MW at $30. G3 offers 200MW at $20. The combined dispatch of the two generators can not be greater than 500MW. With offers totalling 700MW, the network would be constrained and access to the flowgate would be rationed. G3, with the cheaper offer, would be dispatched for 200MW causing G2 to be constrained off by this amount. G3, however, would make payments to G2 through access settlement. Settlement outcomes are illustrated in Table 3.3.

Table 3.3 Optional firm access settlement outcomes

Generator	Dispatch (MW)	Energy settlement	Entitlement to flowgate (MW)	Usage of flowgate (MW)	Entitlement - usage (MW)	Access settlement	Total revenue
G1	300	$15,000	-	-	-	-	$15,000
G2	300	$15,000	500	300	200	$4,000	$19,000
G3	200	$10,000	0	200	(200)	($4,000)	$6,000
Total	**800**	**$40,000**	**500**	**500**	**0**	**$0**	**$40,000**

Through energy settlement, G2 receives the regional reference price of $50 for each unit for which it is dispatched. The payment G2 receives through access settlement is equal to the difference between its entitlement to the flowgate and its usage of the flowgate, multiplied by the flowgate price of $20. Assuming that G2's offer of $30 is reflective of its operating costs, it would earn a $20 margin on the 300MW for which it was dispatched. Through access settlement, G2 also receives $20 for each unit of the 200MW by which it is constrained off (for which it incurs no operating costs). Access settlement therefore puts G2 in the same financial position it would have enjoyed if it had been fully dispatched for 500MW.

The compensation is funded by G3, as a non-firm generator contributing to congestion. G3 receives the regional reference price of $50 on its dispatch, but after paying compensation through access settlement, receives a net price equal to the local price of $30. G3 makes less of a margin than it would have without access settlement applying, but receives more than its offer price so should not regret being dispatched.

3.6 Access pricing

Providing new or additional firm access would increase the network capacity that the TNSP is required to provide under the firm access standard, either immediately or at some point in the future (where spare capacity could be utilised), thus imposing new costs on the TNSP. The OFA model would require the firm generator to pay an amount to the TNSP that covered these incremental costs. The purpose of *access pricing* is to estimate what these costs are. To provide financial certainty for firm generators, the charge to be paid by the firm generator would be calculated and agreed during the access procurement process.

Access pricing would provide a locational signal to generators that is not part of the current arrangements. The access charges paid by firm generators would be *cost reflective* – capturing the incremental transmission costs that are created by their decision to locate in a particular part of the network (or to request additional firm access in the case of an existing generator). The intended outcomes of the pricing methodology that is described below are that, other things being equal:

- generators locating remotely from the Regional Reference Node (RRN) and from other major demand centres would pay a higher price than generators locating closer to the regional reference node or demand centre; and

- generators locating where there is limited spare transmission capacity and where expansion would be required immediately would pay a higher price than generators locating where there is plenty of spare transmission capacity and where no expansion would be needed for some time.

These signals should promote more efficient use of the existing network and, by exposing generators to the long term transmission costs associated with their locational decision, help to co-optimise generation and transmission investment.[50]

We envisage that a consistent pricing methodology, to be applied across the NEM, would be developed during implementation of the OFA model. The governance arrangements for this methodology require further consideration.[51]

3.6.1 Long Run Incremental Costing methodology

Transmission planning is a long-term process and it would not be sufficient to simply calculate the *immediate* cost of the extra expansion required prior to new access rights commencing. The new access may cause a *future*, already planned, expansion to be brought forward. The capital cost would remain the same, but the advancement means that, after applying a discounting rate, there would be an incremental cost in *net present value* (NPV) terms. A methodology in which *all* incremental costs are calculated – present *and* future – is referred to as Long Run Incremental Costing (LRIC).[52] LRIC forms the basis for the access pricing approach.

LRIC is the difference between two costs:

- the baseline cost, which is the NPV of the baseline expansion plan which is in place before the access request is received; and

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50 For further discussion, please see the next chapter.

51 See section 5.6 of chapter 5 for discussion of the appropriate future governance arrangements for demand-side transmission charging.

52 See section 6.3.1 of the staff Technical Report for a discussion of the alternative charging methodologies, Long Run Marginal Cost (LRMC) and deep connection charges, and why LRIC has been preferred.

- the higher adjusted cost, which is the NPV of the adjusted expansion plan - that is, an amendment to the baseline expansion plan to accommodate the new access request.

LRIC = adjusted cost – baseline cost

The expansion plans would be derived using a *stylised* methodology which, by assuming away some of the complexity inherent in transmission planning, should provide stable and smooth expansion outcomes. The methodology is unlikely to capture every aspect of the network and would involve some judgements about future outcomes, but within these limitations it would be a robust basis for determining access charges.

To ensure that the calculated LRIC was nevertheless realistic and representative of actual expansion costs, critical features that determine LRIC characteristics would be included in the methodology. These features include: the measurement of *existing spare capacity*; the *lumpiness* of transmission expansion; the *topology* of the existing transmission system; and the *background growth* of demand and firm generation.

A stylised example of how LRIC would be calculated is provided in the following two figures. Figure 3.4 represents the baseline expansion plan for a single element of the shared transmission network, such as a transmission line or network transformer. Its expansion plan has three drivers:

1. initial spare capacity – the amount of spare capacity on the element in the base year;

2. annual flow growth – the amount by which maximum flows on the element increase each year; and

3. lumpiness – the amount of capacity that would be added through the efficient expansion of that element.[53]

The initial spare capacity would be eroded as the forecast flow increased on the element, typically through an increase in the demand for electricity over time. As soon as the spare capacity was forecast to be exhausted, the element would be expanded in a scale efficient "lump". That expansion would provide new spare capacity, which would be progressively eroded through subsequent flow growth until, eventually, a second expansion was required, and so on.

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53 With electricity transmission, it is not practical to add capacity in very small increments. Economies of scale mean that it is efficient for capacity to be added in "lumps", reflecting the "off-the-shelf" nature of transmission assets. This often results in a transmission upgrade providing a greater increase in capacity than is, initially, required. For further discussion investment "lumpiness" see appendix D of the First Interim Report.

Figure 3.4 Baseline expansion plan for a network element

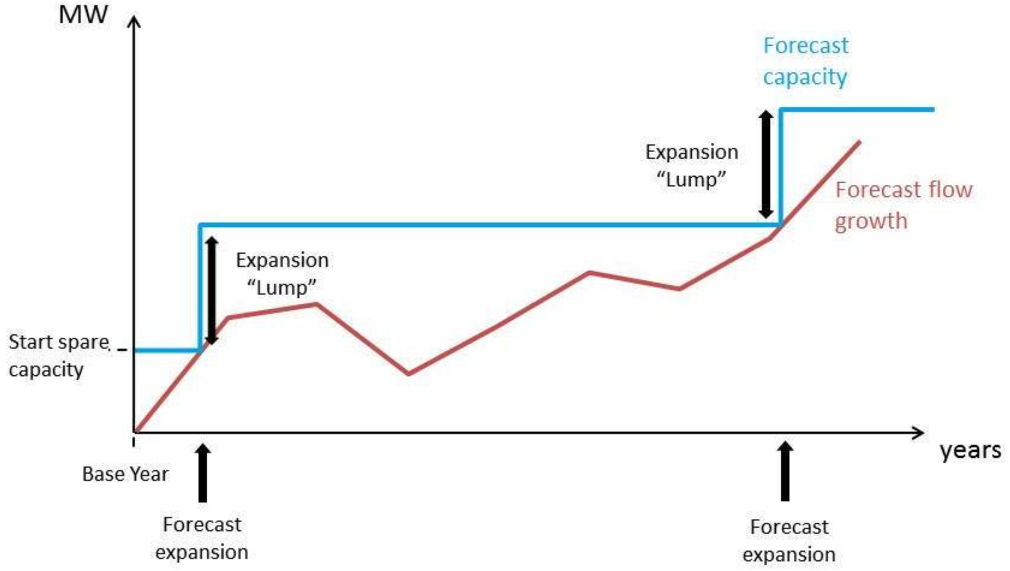
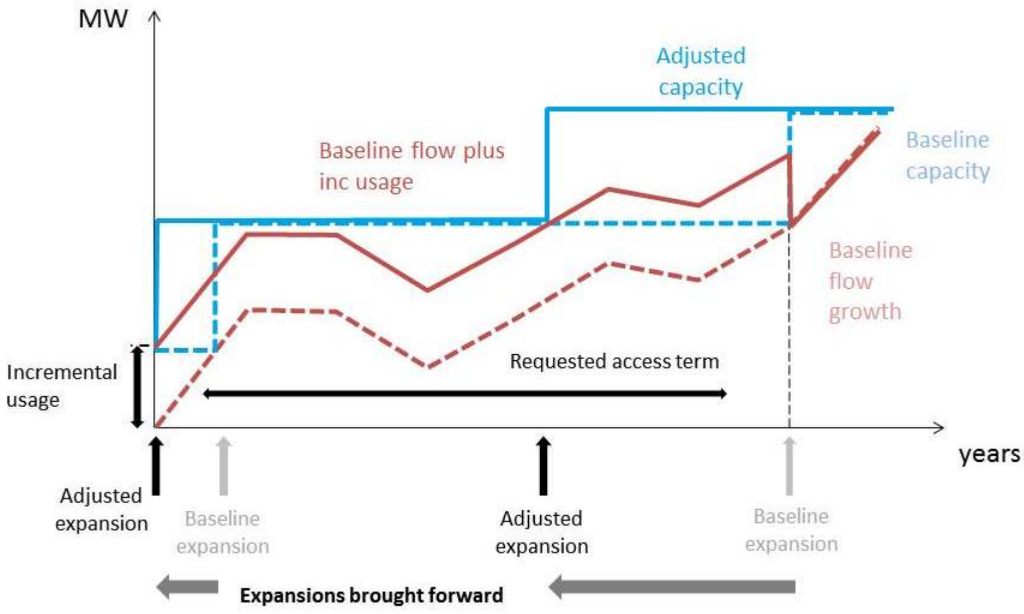


Figure 3.5 illustrates how the request for additional access would result in an adjusted expansion plan for the network element. The effect of the access request is to increase the forecast flow on the network element, and therefore to bring forward the already planned expansions. To model the adjusted expansion plan, two things need to be represented:

1. incremental usage: the extra flow induced on the element by the access request; and

2. access term: the period of the access request and so the period for which the extra flow occurs.

Figure 3.5 Adjusted expansion plan for a network element



The baseline cost and adjusted cost are then calculated by applying an appropriate discount rate to the capital costs implied by the corresponding expansion plans. The access price is the difference between these two costs, summed over all transmission elements in the network.[54]

The access pricing methodology is based on a highly stylised model of transmission expansion which, nevertheless, is expected to broadly reflect the characteristics and levels of a true LRIC forecast. It is designed to provide smooth, transparent and robust prices which would guide efficient generator behaviour whilst covering the cost to TNSPs of providing firm access services.

3.7 TNSP regulation

Firm access rights would be underpinned by transmission capacity on the shared network, the provision of which is a regulated monopoly. Since the shared network would be providing both firm access and meeting consumer load, the firm access service would be treated as a prescribed service, consistent with the current regulation of shared network services for consumers. Regulation for firm access would cover four areas:

1. issuance regulation – requiring TNSPs to follow an access procurement process such as that described in the access procurement section above;

54 In practice, incremental usage will only be material on a subset of elements, generally those elements lying between the new access node and the RRN and so LRIC on only these elements needs to be calculated and summed.

2. pricing regulation – default prices for firm access should be calculated using an approved pricing methodology, consistent with the LRIC principles described in the access pricing section above;

3. revenue regulation – see below; and

4. quality regulation – see below.

3.7.1 Revenue regulation

Revenue regulation would aim to ensure that the *combined* revenue from load services and firm access services was just sufficient to cover the efficient cost of delivering these services.[55] The AER would determine an allowed annual revenue requirement for the TNSP, based on the efficient cost of building, owning and operating a shared network capable of providing current and forecast levels of load services and firm access services to the relevant standards.[56]

Each TNSP would then estimate the amount of revenue expected to be received from providing firm access and, by subtracting estimated access revenue from the allowed annual revenue requirement, a cap on the transmission use of system (TUOS) charges to users of load services would be derived. Aggregate revenue from firm access sales would not be capped; instead, firm access *prices* would be regulated, as discussed above.

Access pricing would be designed to ensure that incremental access revenue and costs were *broadly* matched, but they would not *exactly* match. To the extent that the total costs of providing access differed from the total access revenue within a regulatory control period, the mismatch would be borne by the TNSP. After this time, the discrepancy - whether positive or negative - would be absorbed by users of load services.

If the actual volume of firm access sales within a regulatory control period was less than forecast at the time of the revenue determination, the TNSP would recover less revenue: the TUOS cap would prevent the TNSP from recovering the revenue shortfall from demand-side users. This would be appropriate, because the TNSP's costs would be correspondingly lower.

Similarly, the additional access charges received through the sale of higher than forecast levels of firm access would provide TNSPs with a broadly appropriate amount of revenue to cover the additional costs. Consideration may need to be given to the situation where the additional costs were substantially higher than the extra revenue: for example, where the need for an additional large expansion was triggered. The AER may need to define a mechanism to allow the TUOS revenue cap to be adjusted

55 The Commission notes the interaction of these measures with the Economic Regulation of Network Service Providers rule change currently being assessed. The OFA model would affect inputs into the processes which are the subject of those rule changes, such as forecast expenditure and the regulated asset base, but would not affect the processes themselves.

56 The reliability standard and firm access standard.

upwards in this situation, which might be similar to the existing contingent projects mechanism. The AER might further wish to give consideration as to how the risks associated with any mismatch between these additional revenues and costs would be managed and shared (if at all).

3.7.2 Quality regulation

Quality regulation would provide incentives for TNSPs to maintain access service quality at or above the minimum standard specified in the firm access standard. Incentives would initially be through transparent publication of information on breaches but might increasingly be through financial incentives on the TNSP where breaches occur. Incentives would be based on – and would not exceed - the cost to firm generators of shortfalls of transmission capacity that resulted in entitlements, and so compensation, being scaled back beyond what should be delivered under the firm access standard. Through access settlement, payments by the TNSP would be allocated directly to the generators affected.

The design and timing of any financial incentive scheme for firm access standard breaches would be decided by the AER. It is expected that the TNSP penalty would be equal to some proportion of the costs to firm generators resulting from the breach, which would be achieved through the application of a sharing factor:

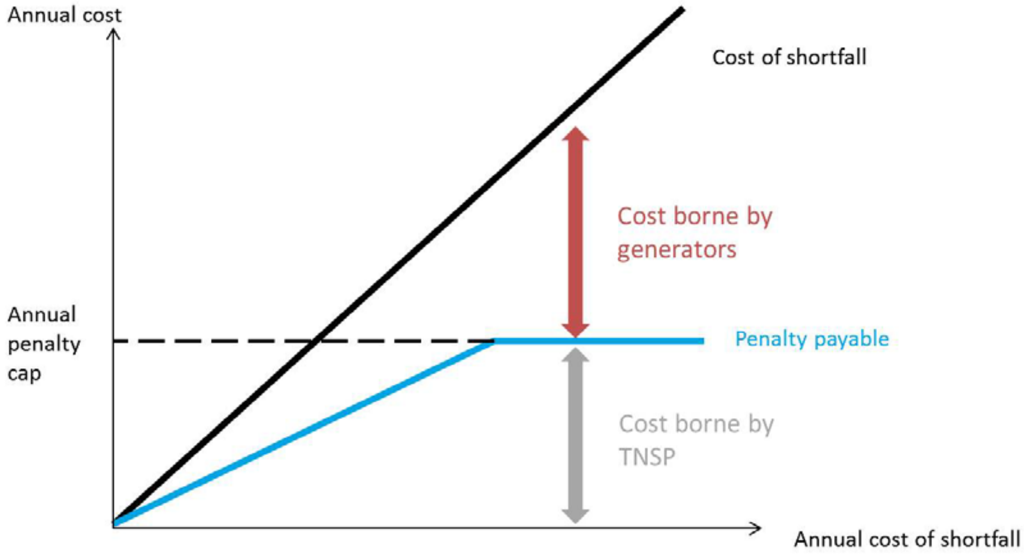
TNSP penalty = incentive sharing factor x shortfall value

The AER should decide on an appropriate mechanism for setting a sharing factor between zero and 100 per cent. The sharing factor might increase over time, to sharpen the incentives on TNSPs. If it followed the design of similar quality incentive schemes elsewhere, the AER would set a fixed sharing factor that applied until aggregate penalties reached a predetermined limit, after which the sharing factor would be set to zero so that no further penalties would apply, as illustrated in Figure 3.6. However, other designs are possible, and the precise approach and degree of AER discretion would need to be determined.[57]

While these incentive arrangements would be asymmetric, we envisage that TNSPs might be able to earn additional revenue through sales of short-term firm access. This would be possible where a TNSP had sufficient spare capacity to release additional rights without incurring expansion costs or breaching capacity. If optional firm access forms the basis of final recommendation, we would anticipate developing this concept further.

57 Consideration would also need to be given to the interaction of incentives on TNSPs with liability caps that exist through immunities in favour of network service providers under the NEL.

Figure 3.6 An incentive sharing regime



3.8 Transition

Transition processes would apply prior to, and in the early years following, implementation of the OFA model. The objectives of these processes would be:

- to mitigate any sudden changes to prices and margins for market participants (generators and retailers) on commencement of the OFA regime;
- to encourage and permit generators – existing and new – to acquire and hold the levels of firm access that they would choose to pay for;
- to give time for generators and TNSPs to develop their internal capabilities to operate new or changed processes in the OFA regime without incurring undue operational or financial risks during the learning period; and
- to prevent abrupt changes in aggregate levels of agreed access that could create dysfunctional behaviour or outcomes in access procurement or pricing.

Importantly, the transition process should not delay or dilute the efficiency benefits that the OFA model is designed to promote.

The main transition mechanism would be the allocation of transitional access to existing generators. Transitional access would act identically to other firm access except that it would not need to be procured from a TNSP and generators would not pay access charges for it.

The transitional allocation process would have four stages:

- Generators' access requirements – the level of firm access they would need to have unfettered access to the RRN – would be calculated, based on historical generation patterns.[58]
- These access requirements would be scaled back to the extent necessary to ensure that all transitional access could be accommodated by the shared network.
- This scaled access level would be sculpted back over time, so that transitional access reduced over a number of years and then expired.
- An auction would be established to allow generators to sell some of their transitional access or buy additional transitional access from other generators.

Another transition mechanism would be that no financial incentives, as discussed in TNSP regulation above, should apply to TNSPs in relation to breaches of the firm access standard in the initial years of its operation. The learning period given may be up to five years, but should be at least the remainder of the prevailing regulatory control period.

In summary, the transition process would help to ensure that, from the commencement of the OFA regime, existing generators would hold agreed access amounts that provide them with firmness of access to the RRN similar to the de facto access they enjoy currently. Aggregate access holdings would initially be commensurate with transmission capacity but, as these are sculpted back over a number of years, transmission capacity will be freed up to support new access issuance, charged for in accordance with access pricing, to existing or new entrant generators.

3.9 Inter-regional access

The descriptions of optional firm access in the preceding sections relate only to *intra*-regional access: access from a generator's point of connection to the transmission network to the local regional reference price. However, the optional firm access model also establishes a framework for *inter*-regional access: a mechanism for hedging the price difference between two regions.

Generators and retailers would be able to procure inter-regional access on *interconnectors*, which connect different NEM regions, and would benefit from hedging the inter-regional price difference.[59] Their purchase of access rights would fund

58 Market network service providers (MNSPs) would be treated as generators for the purpose of allocation transitional firm access.

59 Flows between two different RRNs occur on interconnectors. In dispatch and settlement, they represent the net flow between two regions. Interconnectors are, however, a conceptual representation of connection between two regions. In practice, the physical assets which provide the interconnection between two different RRNs may also provide connection within a region, apart from those transmission lines which actually cross regional boundaries. There may also be several transmission pathways between two regions, which are represented as a single aggregate interconnector (apart from DC interconnectors, which are separately controllable and separately dispatched).

expansion of interconnector capacity.[60] By providing a mechanism for market participants to internalise the costs and benefits of interconnector expansion, inter-regional access provides for market-led development of interconnector capacity.

The holder of an inter-regional access right would be entitled to the price difference between two regions on its access amount.[61] This is similar to the payment from the current Settlements Residue Auction (SRA) instrument.[62] However, since the SRA payment is based on actual interconnector flows, it is reduced when a generator causes the interconnector to be constrained off.[63] Under the OFA model, the generator causing the problem would compensate the inter-regional access holder to ensure that, despite the reduction in interconnector flow, the access settlement payment did not reduce. Access payments would, however, still be scaled back if transmission capacity was reduced. Nevertheless, holders of inter-regional access rights would receive a far firmer payment than current holders of SRA units.

Inter-regional access is included in the OFA model for two reasons. Firstly, many transmission elements provide a combination of inter- and intra-regional access, which are represented in the model by *hybrid flowgates*.[64] To ensure that access settlement balances on hybrid flowgates, interconnector usage and entitlements must be defined, and interconnector access payment made by or received from the interconnector parties. So long as there are hybrid flowgates, the inclusion of inter-regional access is unavoidable.

Secondly, although interconnector parties could play a purely passive role in the OFA model, there are potential efficiency benefits from allowing *interconnector parties* to decide their levels of *inter*-regional access, just as there are efficiency benefits in allowing *generators* to decide their levels of *intra*-regional access. Because the benefits of inter-regional access are potentially dispersed across a number of sectors, representatives of all of these sectors should – to the extent possible – be involved in that decision process.

60 Along with contributions from TNSPs for the benefits which they would enjoy from interconnector expansion – see inter-regional access procurement in section 3.9.1.

61 This would be the case where that price difference was positive. Note that access amounts would be scaled to determine entitlements using the same scaling process described in the Firm Access Standard section above.

62 See Box 7.2 of the First Interim Report for an explanation of the inter-regional settlements residue and settlements residue auction.

63 The inter-regional settlements residue which underlies the settlement residues auction can even become negative, although the holder of SRA units is protected in this case. See appendix A.5 of the First Interim Report for an explanation of counter-price flows.

64 Underlying hybrid flowgates are *hybrid transmission constraints* that include both generator and interconnector terms. Transmission constraints are formulated by AEMO to reflect the limits of the network, and therefore place limits on the combination of generation and interconnector flows that can be dispatched.

3.9.1 Inter-regional access procurement

Market participants (i.e. both generators and retailers) could seek to procure additional inter-regional access, just as generators could for intra-regional access.[65] Where TNSPs identified potential inter-regional expansion projects, market participants would be invited to express their interest in obtaining additional inter-regional access rights through submitting bids.[66] An inter-regional expansion project would proceed if sufficient bids were received to cover its costs, and successful bidders would gain access rights.

The access right might be attractive to market participants whose regional market is small with volatile prices. Firm inter-regional access could give those participants effective access to a large, more stable, regional market.

Inter-regional expansions might provide benefits to other parties, in addition to the holders of the new inter-regional access rights. Benefits might flow to:

- *TNSP(s) in the importing region(s)*, who would be able to use the additional inter-regional transmission capacity to maintain their demand-side reliability standards at a lower cost than through intra-regional expansion;

- *TNSPs*, if the expansion helped to avoid capital expenditure that would otherwise be required to maintain their firm access standards to provide intra-regional access to firm generators; and

- the *market as a whole*, through benefits such as increased regional or inter-regional competition and increased liquidity from (effectively) larger forward markets.[67]

To help to ensure efficient inter-regional expansion, parties assessing these benefits could contribute to expansion costs by making separate bids into a central agent.[68] If sufficient bids were received, the expansion would proceed.

Since TNSPs are regulated, any bids made by them would have to be justified through a RIT-T, or similar cost-benefit analysis, in order to demonstrate that the bid level was no higher than the forecast benefits. This would apply to benefits relating to meeting reliability standards and intra-regional firm access standards, and, potentially, to market-as-a-whole benefits.

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65 Because inter-regional access does not relate to a particular power station or generator node, there would be no need to confine holdings to generators.

66 See section 10.3.8 of the staff Technical Report for discussion of the issues surrounding demand-driven expansion.

67 Where the removal of the risk of price separation between two regional markets effectively allows them to operate as a single, combined, forward market.

68 Further consideration as the institutional arrangements to apply would be required, but AEMO as NTP might be a likely candidate to be the central agent.

It would be important that these parallel tests did not double count benefits, either TNSPs counting private benefits that market participants had already accounted for or TNSPs counting the same public benefits twice.[69]

Inter-regional access rights would be allocated only to the successful market participant bidders.[70] Total rights issued would be limited to the amount of inter-regional capacity provided by the expansion. Rights would not be issued to the other parties because the benefits to them of the expansion would not depend on them acquiring access to the inter-regional price difference.[71]

3.9.2 Inter-regional firm access standard

TNSPs would be required to maintain capacity on hybrid flowgates in accordance with the firm access standard, ie to meet the total of firm access requirements when scaled to reflect the network operating conditions. Hybrid flowgates would include interconnector entitlements, so the issuance of inter-regional access (whether in transition or through future inter-regional expansion), would mean that inter-regional transmission capacity must be maintained and could not be cannibalised through TNSPs using the capacity to provide new intra-regional firm access to generators connecting on inter-regional transmission paths.

Although inter-regional expansion would commonly be a joint project between two TNSPs, firm access standard obligations would nevertheless fall solely on the TNSP in whose region the congested flowgate was located.[72]

3.9.3 Inter-regional pricing

There would be no standard pricing methodology to determine inter-regional access charges. Rather, the National Transmission Planner (NTP) and TNSPs would identify inter-regional expansion projects and the charges to be recovered from successful bidders would be based on the *actual* project cost, rather than using a stylised expansion model.[73]

3.9.4 Inter-regional access settlement

Inter-regional access settlement would work by allocating the Inter-Regional Settlements Residue (IRSR) to holders of inter-regional access rights. The pool of funds available would be equal to the price difference between two regions, multiplied by the

69 See section 10.3.6 of the staff Technical Report.

70 Market participants' bids would be conditional on receiving inter-regional access rights. Bids from other parties would be conditional only on the new inter-regional expansion actually occurring.

71 See section 10.3.7 of the staff Technical Report.

72 Where the location was unclear – for example in the case of stability constraints – the firm access standard obligation would need to be allocated and managed through some agreement between the two TNSPs.

73 See section 10.3.5 of the staff Technical Report.

interconnector flow, as it is currently. In addition, however, non-firm generators whose dispatch caused the interconnector flow to be diminished would make payments into the IRSR through access settlement.

Payments to holders of the inter-regional access rights would be equal to their access entitlement multiplied by the price difference between two regions (where that price difference is positive).

It is a notable effect of the model that the inter-regional settlements residue would always be positive, even where there are counter-price flows.[74] Counterprice flows on interconnectors might still arise, where generators in the exporting region were in merit relative to the importing region's reference price, despite the exporting region having a higher regional reference price. Through the access settlement process, interconnectors would be compensated for any counterprice flows, preventing any negative settlements residue from arising.[75] The inter-regional access right would therefore be firmer than existing SRA units.

3.9.5 Transitional inter-regional access

Transitional inter-regional access would be allocated in the transition process, but only to the extent that this could be done without causing any additional scaling back of generators' transitional access.[76] This reflects the priority in dispatch that generators have over interconnectors in the current arrangements.

It is proposed that, unlike generator transitional access, inter-regional transitional access would not be scaled back over time but would remain at its initial level indefinitely. This is because many of the drivers for sculpting back generator transitional access do not apply to interconnectors. For example, unlike generators, interconnectors will not ultimately close. There is also no risk associated with access hoarding, since inter-regional transitional access would be held in trust by the central agent and auctioned regularly to market participants, through an auction process similar to the existing settlements residue auction.[77]

The proceeds from auctioning inter-regional transitional access would be passed to consumers in the importing region as an offset to TUOS charges.[78] Thus, generators, retailers or other parties could potentially acquire inter-regional access through the

74 See section 10.3.2 of the staff Technical Report.

75 This would therefore remove the current obligation on AEMO to intervene when there are counter-price flows and "clamp" interconnectors to prevent negative inter-regional settlements from exceeding $100,000.

76 MNSPs would be treated as generators for this purpose.

77 The inter-regional access auctions would effectively take the place of the settlements residue auction.

78 This is the same as the current arrangements for inter-regional settlements residue and settlements residue auctions. However, as discussed in chapter 5, it might no longer be appropriate to use these to adjust *locational* TUOS charges.

auction. Successful bidders would receive the payments under access settlements described above.

3.10 Implementation

The optional firm access model described in this chapter would make fundamental changes to the NEM, and would represent a very significant implementation task. Implementation would not be at a scale comparable to the original creation of the NEM, but it would be perhaps the most significant change since that time. To implement the model would require:

- possible changes to the National Electricity Law;
- extensive rule changes;
- additions to the market's settlement functions;
- possible changes to institutional arrangements;
- the development of the access pricing methodology;
- the development of the firm access standard;
- some changes to how TNSPs' revenue is regulated, and
- new areas of TNSP regulation.

The Commission, if recommending the optional firm access model in the final report for the Transmission Frameworks Review, will need to consider how best it should be implemented, and whether to advise SCER on a path that could be designed for implementation.

Implementation would be a complex and multi-faceted task over several years, significantly more complex than could be achieved by lodging rule changes. It would likely require the establishment of a dedicated taskforce with input from the AEMC, AER, AEMO and industry, to drive the variety of detailed design, legislative and rule change tasks.

Stakeholder views on how implementation might best be undertaken, if this model were recommended, are welcomed through this consultation process.

4 Assessment of access models

Box 4.1: Summary of this chapter

This chapter assesses the two models for transmission access - non-firm access (NFA) and optional firm access (OFA) - against the objectives that were set out in the First Interim Report. The overarching aim of this review is to provide arrangements for transmission that are likely to optimise investment and operational decisions across generation and transmission to minimise the expected total system costs borne by electricity consumers.

The OFA model would create the following improvements over the current arrangements for transmission, which would persist under the NFA model:

- *Improved support for a deep and liquid contract market* - by providing:
  - a mechanism for generators to obtain firm financial access that is not affected by congestion; and
  - a mechanism for market participants to obtain inter-regional access, which should encourage contracting between generators and retailers in different regions.
- *More efficient investment in generation and transmission* - by establishing:
  - clear and cost-reflective locational signals for new generation investment through access pricing, encouraging the co-optimisation of transmission and generation investment;
  - market-led development of the transmission network, where generators' procurement of firm access would fund and guide network expansion; and
  - a new mechanism for the efficient expansion of inter-regional transmission capacity which would allow financially interested parties to internalise the costs and benefits of interconnector capacity.
- *More efficient dispatch of generators* - by reducing the current incentives on generators to engage in disorderly bidding.
- *More efficient operation of transmission networks* - by exposing TNSPs to some part of the value of network availability.

If the OFA model is to be recommended, these benefits would need to outweigh its implementation costs, which are likely to be significant. The model would represent a substantial change to the NEM arrangements and would add complexity. It would also introduce new incentives, and therefore risks, for TNSPs.

4.1 Introduction

Chapter 1 highlighted the outcomes we have identified in this review as being the aims of well structured and targeted transmission arrangements. These form the basis for the following comparison of the transmission access arrangements that were described in the previous two chapters - the non-firm access and optional firm access models.

Consistent with promoting the NEO, the objective of this review is to provide arrangements that are likely to optimise investment and operational decisions across generation and transmission to minimise the expected total system costs borne by electricity consumers.[79] This will occur where:[80]

- TNSPs have incentives to efficiently invest in and operate their networks to meet consumer requirements at least cost and support a competitive generation sector. They should ensure that existing capacity is used efficiently and that the network is expanded in an efficient and timely manner.
- Generators have incentives to offer their energy at an efficient price and to invest in new plant where and when it is efficient to do so. They should have access to deep and liquid contract markets.
- The policies, incentives and signals that govern transmission and generation decisions are coordinated to promote consistent decision making between the regulated and competitive sectors of the NEM. Transmission and generation investment should be co-optimised.
- The safety, reliability and security of the transmission system is maintained.

Any implementation and transitional costs should not outweigh the benefits of moving to a new framework. As such, these costs must be taken into account in considering the relative merits of any proposed reforms.

The assessment undertaken in the remainder of this chapter is qualitative. As noted in chapter 1 of this report, the AEMC is currently undertaking quantitative analysis to provide further input into our assessment of the relative costs and benefits of the alternative access models. We expect to publish the results of this modelling later this year. Some very important potential benefits, such as those relating to impacts on contract markets and on investment decisions, will be hard to quantify.

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79 The Terms of Reference for this review specify that we should have regard to the NEO and other principles agreed by COAG, as specified in section 1.3 of this report.

80 See chapter 3 of the First Interim Report for further discussion of this assessment framework.

4.2 Impact on contract market

The decision to invest in generation is influenced by, among other things, the ability of generators to underwrite contracts to manage the trading risks that they face.[81] Where generators rely on contracting to manage trading risk, a deep and liquid contract market is required to support generation investment. Investors might rely on a long-term contract, or if they are confident that the contract market is sufficiently deep and liquid, can rely instead on a series of short-term contracts.

The ability of generators to sell forward (derivative) contracts against their output allows them to manage (or hedge against) the risk of spot price volatility. Where a generator sells a volume of forward contracts, and is dispatched for an equal quantity, it is guaranteed to receive the contract price on that volume through the receipt (or payment) of contract for difference payments where the spot price is lower (or higher) than the contract price. An investment product that works in this way, perfectly offsetting the price movement in the spot market, is referred to as a hedge.

The ability of generators to hedge against price volatility is important as it provides greater financial certainty to investors: they can be assured of receiving a future stream of predictable and stable revenues. More certainty means less risk, which in turn flows through to lower financing costs for investors. Ultimately, this should result in lower prices for consumers, with generators able to offer electricity (both spot and contract) at lower prices than they otherwise would. The higher level of certainty should also make investment in the electricity sector more attractive than it otherwise would be.

4.2.1 Contract markets with non-firm access

Currently, congestion has two negative impacts on the ability of generators to sell forward contracts against their output. The first is dispatch risk. Congestion prevents generators from selling all of their offered output at the regional reference price.[82] Whenever a generator has contracted for a higher amount than it is dispatched for, it is not perfectly hedged: it is exposed to the cost of making contract for difference payments but does not earn revenue by selling into the spot market to back those contracts. Potentially, the cost is very high. Generators that are exposed to congestion are therefore able to hedge a lower proportion of their generating capacity than generators that are not exposed.[83]

The second impact relates to volatility. Where congestion was stable and predictable, generators could contract forward for the quantity of output for which they can be

81 A generator might also vertically integrate with a retailer to manage trading risk, guaranteeing an agreed price for some part of its generating capacity.

82 Other risks, such as outages of power station generating units, may also deter generators from contracting for all of their output.

83 Generators might deliberately sell a higher volume of contracts than their expected level of dispatch in the expectation of the contract price exceeding the spot price. Their motivation in this case is speculative - deliberately taking a risk, rather than the offsetting of risk which is achieved by hedging, i.e. contracting up to expected dispatch volume.

confident of being dispatched, albeit that was not 100 per cent of their generating capacity. However, congestion tends to be volatile and unpredictable, and the level of generation that the generator can hedge is correspondingly lower.

Under the Non-firm Access (NFA) model, which does not establish any mechanism for managing congestion risk, these negative impacts on the contract market should be expected to persist.

4.2.2 Contract markets with optional firm access

By decoupling access from dispatch, the Optional Firm Access (OFA) model would create the ability for generators to hedge the risk of congestion. Under normal operating conditions, a constrained off firm generator would earn the difference between its local price and the regional reference price on its access amount, which should at least equal the margin it would have earned by being dispatched.[84] Firm access therefore provides the financial certainty for generators to offer forward contracts on a volume reflective of their access amount. Generators might be expected to contract for a volume somewhat less than their nominal access amount to reflect the probabilities of less than optimal network operating conditions, where access is correspondingly scaled back - see previous chapter.

The higher expected level of hedging that would result, as compared to under the NFA model, should result in the benefits described above - higher levels of financial certainty for investors in the electricity sector, lower financing costs and lower prices for consumers.

Conversely, non-firm generators would face a higher degree of basis risk - of earning a local price (after payment of compensation to firm generators) that is less than the regional reference price (but at least equal to their offer price).

The OFA model would also introduce an inter-regional access product, allowing generators and retailers to manage the risk of inter-regional price differences. This would enable market participants to contract with counter-parties across regional boundaries with a higher level of financial certainty than can currently be achieved.[85] The result should be a more integrated national market, with generators in lower priced regions contracting with retailers in higher priced regions, with resulting benefits to consumers in higher priced regions. A further benefit may be increased retail competition: by decreasing the risk of inter-regional price differences, firm inter-regional access may encourage retailers in one region to enter into other regional markets.

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84 The local price is the price of supplying a marginal unit of electricity at a point in the network. It is equal to the regional reference price minus the flowgate price - see Box 3.3 in the previous chapter.

85 See discussion in previous chapter of why the inter-regional access product would be firmer than the current settlements residue auction instrument.

The optional firm access pricing methodology has been designed with the aim of further supporting financial certainty for generators. The access charge would be fixed for the life of an access agreement, similar to connection charges currently.

4.3 Impact on investment

4.3.1 Non-firm access - regulated planning approach

Currently there is a regulated planning approach to transmission investment. This would persist under the NFA arrangements. TNSPs would be required to assess the need for new investment based on rules, regulatory obligations and assumptions about the value that consumers place on reliability and quality. Without market signals, it is very difficult to capture this value. However, there are incentives and planning approaches - such as the RIT-T, transparent planning and stakeholder consultation requirements - which encourage the implementation of transmission development plans at least cost.

The Commission broadly considers that current planning arrangements are delivering efficient outcomes.[86] There is no evidence to suggest that TNSPs are failing to meet demand-side reliability standards. TNSPs undertake the necessary steps to assess the need for more inter-regional transmission capacity. However, application of the RIT-T does not (and should not) result in all congestion being relieved, nor does it attempt to capture the value that generators place on certainty of access.[87]

The regulated planning approach has the potential to distort competitive market outcomes in terms of generation investment. Network planning requires TNSPs to predict the least-cost combination of generation and transmission to meet forecast load, and to plan the network accordingly. It can potentially result in imperfect co-optimisation: a TNSP knows the costs of transmission, but has imperfect information regarding the costs of generation. The TNSP's transmission investment decisions may have an effect on generators' investment decisions, by reducing congestion in certain parts of the network, and therefore encouraging generator investment in those areas. This creates a bias towards the generation and transmission development path towards that which the TNSP predicts, even where a lower cost combination exists.

If the regulated planning approach delivers a transmission path that is significantly different from that required by competitive investment in generation, then a different generation pattern could emerge despite the locational signals provided by congestion.

86 See section 5.2.3 of the First Interim Report.

87 See section 5.1.2 and 5.3.3 of the First Interim Report for the divergence of stakeholder views on the current arrangements. Broadly, large government-owned generators in Queensland and NSW submitted that the existing transmission planning and investment arrangements have delivered reasonably effective outcomes, and that increased network investment will continue to limit congestion in the NEM. By contrast, privately owned generators in Victoria raised a number of concerns.

There is therefore a risk that the transmission assets that the TNSP has invested in would be stranded, and that alternative transmission assets would need to be built.

Whenever the regulated planning approach delivers a transmission path that is not co-optimised with generation investment, the result is a higher combined cost of generation and transmission than could otherwise be achieved. These costs are borne largely by electricity consumers, who have only limited influence on these investment decisions. This does not represent an ideal alignment of risk and decision making.

A further issue with the current arrangements is the absence of price signals to generators of the impact of their locational decisions on transmission network costs. The result may be inefficient locational decisions that, again, increase the overall cost of transmission and generation.

The Commission has previously noted that certain locational signals such as transmission losses, congestion and inter-regional price variation do provide a degree of incentive for efficient generator locational decisions.[88] However, these signals are incomplete, as they do not signal the long term costs of transmission.

The absence of a generator transmission charge in the NFA model would therefore be likely to result in potential efficiency gains not being realised. For instance, proximity to a gas pipeline is likely to be important to a gas-fired generator, but it would not be exposed to the cost of transmission investment that may be required to support its locational decision.

4.3.2 Optional firm access - market-led development

The OFA model would establish market-led development of the transmission network. The purchase of firm access by generators would fund and guide network expansion, with TNSPs required by the firm access standard to plan the network to meet all firm access concurrently, while continuing to meet load reliability planning requirements.

The OFA model would create a clear and cost-reflective locational signal for new generation investment that is currently missing in the NEM. Locational signals would be provided to both firm and non-firm generators:

- firm, in the form of access pricing; and
- non-firm, in the form of compensation payments through access settlement and the risk of being constrained off.

The access pricing methodology aims to be cost reflective: it should capture the incremental network costs of a generator's decision to locate in a particular part of the network. Firm access would be cheaper where there is existing spare network capacity than where there is not. Firm access would be cheaper where a generator located closer

88 See section 2.3 of this report.

to load in more meshed parts of the network than where it located further from load in less meshed parts of the network.

It would be rational for a generator to be non-firm if the cost of firm access was greater than the expected cost of compensation it would pay to firm generators through access settlement. This would be the case where the expected cost of compensation was low, i.e. the generator was unlikely to contribute to congestion. Again, an appropriate locational signal is given, encouraging generators to locate in uncongested parts of the network.

The OFA model should achieve a higher degree of co-optimisation than under the regulated planning approach that would persist in the NFA model. OFA would expose generators to cost-reflective access pricing. By making the cost of transmission part of a generator's investment decision, OFA should encourage co-optimisation of transmission and generation investment: the investor should seek the location for a power station which minimises the combination of its operating and establishment costs and the cost of transmission. In making a locational decision a generator would therefore account for both its private costs and also the costs to the transmission network. Better co-optimisation of investment in other energy networks, where they are used as fuel sources, should also result.

In an appropriate alignment of decision-making and risk, where generators make inefficient investment decisions, they would bear the cost of any expansion of the transmission network that was undertaken to give them firm access. This represents an improvement over the current planning arrangements, where consumers bear the risk of inefficient transmission decisions.

The OFA arrangements would give firm generators the ability to trade access rights, allowing for efficient re-use of network assets. If, instead, access procurement created an access right for the life of the asset that could not be traded, the result would be inefficient duplication of assets where a new party sought access and the original access holder no longer valued its access right (or, more correctly, valued its access right less than the cost of providing access through further network expansion).

4.3.3 Interconnector investment

Currently, and under the NFA model, interconnector investment may occur on the basis of net market benefits.[89] The cost is borne by users of load services and passed through to consumers. The benefits of the interconnector may, however, be eroded by the subsequent location of new generation on or near the interconnector which degrades its capacity. Those generators would benefit from a relative lack of congestion, but would not compensate consumers for the cost of the interconnector (or

89 See section 4.2.3 of the First Interim Report for a description of the RIT-T, which requires TNSPs when considering a transmission investment to examine the costs and benefits of credible options to establish the one which maximises net market benefits. The benefits provided by an interconnector may include the meeting of reliability standards from cheaper generation, improved retail competition and the sharing of reserves between regions.

for the loss of benefits that the interconnector provided, if the new generation does not provide the same benefits that the interconnector did).

The OFA model would allow interested parties to internalise the costs and benefits of interconnector capacity. The result should be an efficient level of interconnector investment: where the benefit of access (the inter-regional price difference) exceeds the price of access (the cost of interconnector expansion) interconnector expansion should occur.

The creation of inter-regional access rights also protects against the erosion of interconnector benefits by subsequent generator entry. The firm access standard would require TNSPs to maintain inter-regional access, so they could not cannibalise interconnector capacity by using it to meet intra-regional firm access. Where generators located on or near the interconnector and chose to be non-firm, they would compensate holders of inter-regional access through access settlement for any congestion they caused. The ability of inter-regional access holders to trade those rights again allows for efficient re-use of interconnector capacity.[90]

4.4 Impact on generator bidding behaviour

4.4.1 Non-firm access and disorderly bidding

Currently, and under the NFA model, financial access to the regional reference price is linked to a generator's dispatch level. Generators located in a congested part of the network have an incentive to offer electricity at a price less than their short run marginal cost - a process known as disorderly bidding.[91] Congestion means that their bidding will not affect the regional reference price. This may result in productive inefficiency, with more expensive generation (in terms of operating costs) dispatched ahead of cheaper generation. It also contributes to the lack of financial certainty described in the discussion of the contract market in section 4.2, where a generator's revenue stream is dependent on the level of congestion and the offer prices and availability of generators nearby.[92]

4.4.2 Optional firm access addresses disorderly bidding

The OFA model would reduce the incentives for disorderly bidding by decoupling access to the regional reference prices from an individual generator's dispatch level, and should therefore enhance productive efficiency.[93] The dispatch process would be

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90 Trading of inter-regional access rights could potentially allow for the use of assets that were created as part of an interconnector expansion to be used instead for intra-regional purposes.

91 See First Interim Report appendix A.1 for a simple numerical example and further explanation of disorderly bidding.

92 Disorderly bidding may also weaken locational signals for new generators, who may locate in congested parts of the network knowing that they can obtain a share of scarce network capacity.

93 It also increases financial certainty and improves locational signals, as discussed above - through the firm access product and access pricing - rather than by reducing disorderly bidding.

unchanged, but the changes introduced by access settlement would change generators' bidding incentives and should lead to improved dispatch outcomes. Access settlement exposes non-firm generators to their local price. This should incentivise generators to offer their energy in a cost reflective manner – i.e. to reduce incentives for disorderly bidding. If a non-firm generator offers electricity at a price less than its short run marginal cost, it risks setting the local price at this level, and running at a loss.

4.4.3 Strategic behaviour with optional firm access

Although the OFA model addresses existing forms of disorderly bidding, consideration should be given to whether it would create different perverse incentives, by encouraging behaviour that makes sense for an individual generator but that results in inefficient outcomes from a market perspective. The following analysis concludes that the optional firm access model would create a strategic "tug-of-war" between firm and non-firm generators that would tend to:

- drive dispatch of firm generators towards the amount of firm access that they hold; and
- drive dispatch of non-firm generators towards whatever level of transmission capacity is left.

Generators that are located in a congested part of the network may have some influence over the local price. They may be able to increase the local price by withholding capacity (or increasing their offer prices). As a result, they may ease congestion, and move the local price closer to the regional reference price. Or they can attempt to exacerbate congestion, and decrease the local price, by increasing their availability (or decreasing their offer prices).

The compensation payable by non-firm generators, when there is congestion, is equal to the difference between the local and regional reference prices. Non-firm generators therefore have the incentive to minimise this difference. To the extent that they can influence the local price, they should attempt to raise it by withholding capacity (or increasing their offer price). But they do so at the expense of being dispatched for a lower quantity (remembering that a non-firm generator gets paid its dispatch quantity at the local price). For an individual non-firm generator, it would make sense to engage in this behaviour if the percentage increase in the local price it achieved was greater than the percentage decrease in its dispatch quantity (assuming constant unit costs of production). Its profit-maximising behaviour would therefore depend on the extent of local pricing influence it exerts.

For firm generators, incentives operate in the opposite direction: they wish to maximise the compensation they receive when there is congestion by increasing the difference between the local and regional reference prices. To the extent that they can influence the local price, they should attempt to decrease it by increasing their offered availability (or decreasing their offer price). But they do so at the expense of being dispatched for a higher quantity, and therefore reducing the compensation to which they are entitled (remembering that payments through access settlement are on the quantity for which a firm generator is constrained off: if it is dispatched for its access level, it receives no compensation at all). For an individual firm generator, it would make sense to engage in this behaviour if the percentage decrease in the local price it achieved was greater than the percentage change in the quantity by which it is constrained off. If the firm generator is dispatched for more than its access level, it becomes liable to pay compensation to other generators. Its access level therefore represents the upper limit to this kind of strategic bidding.

In summary, where non-firm generators exert local pricing influence, they will tend to give up some level of dispatch. Where firm generators exert local pricing influence, they will tend to gain some level of dispatch, but only up to their access level. In combination, these individual generator incentives will tend to drive dispatch of firm generators towards their firm access level and dispatch of non-firm generators towards whatever transmission capacity is left.

4.5 Impact on transmission operational decisions

The NFA model would continue the current incentives on TNSPs to operate transmission networks efficiently, which do not fully capture the value of network capacity to market participants.[94]

The firm access standard introduced by OFA places an obligation on TNSPs to both plan and *operate* the transmission network such that sufficient transmission capacity is available to meet all firm access (in the proportions according to the various tiers of operating conditions). A failure to meet the firm access standard results in a measurable cost to firm generators: the shortfall in access to the regional reference price. The OFA model would expose TNSPs to a share of this cost, which might increase over time, and would therefore create financial incentives on TNSPs to maximise network availability when it is most valuable.

This approach would provide a strong signal to TNSPs to manage the network consistently with the way in which capacity is valued by the market at any point in time. Exposing TNSPs to even some part of the cost to the market of network unavailability may have a large effect on TNSP behaviour. However, it would expose TNSPs to movements in the spot market price, which might represent a significant change in the risk profile of their businesses.

The ability of TNSPs to sell short term access and earn additional revenue above their annual revenue cap would create a further incentive to maximise network availability.

4.6 Cost and complexity

As noted in the previous chapter, implementing the arrangements to support optional firm access would represent a very significant change to current arrangements. Doing so may be expected to result in significant implementation and transitional costs. The

94 See section 3.2.2 of the First Interim Report.

costs associated with NFA, which largely continues the current arrangements, would be minimal. The benefits of OFA over NFA, as described above, would therefore need to result in materially more efficient outcomes to justify the costs associated with moving away from current arrangements. Stakeholders' submissions in response to this report will be important in informing the Commission's consideration in this regard.

The new arrangements contemplated under the OFA model would introduce complexity, particularly the development and use of a firm access standard and an access pricing methodology. The Commission believes that these are appropriately designed mechanisms to achieve the model's objectives. Nevertheless, the associated complexity would require adaptation by the businesses who participate in the NEM if the benefits of the model are to be fully realised. Generators, and to a lesser extent retailers, would be incentivised to adapt, as they stand to benefit from arrangements for firm access and inter-regional trading. Careful consideration would need to be given to how TNSPs would be encouraged to adapt, as their participation in access pricing and planning in accordance with the firm access standard would be critical.

The optional firm access model addresses significant risks that are associated with the current arrangements, providing more certainty of access, more financial certainty and better co-optimisation of transmission and generation investment. However, it would create new categories of risk: primarily by exposing TNSPs to some part of the economic cost of network unavailability and by exposing non-firm generators to the costs of congestion. The Commission believes that these risks are appropriate as they would encourage efficient outcomes. However, again consideration needs to be given to how businesses would adapt. Well designed transitional arrangements would be important in this respect.

More broadly, there are risks associated with moving away from a regime that has delivered transmission and generation investment to date, to an untested regime that is fundamentally different, and which risks creating unintended consequences.

5 An enhanced transmission planning and pricing framework

Box 5.1: Summary of this chapter

This chapter sets out the Commission's proposals for a holistic set of transmission planning and pricing arrangements to further promote efficient investment in, and use of, the transmission network across the NEM over the long term.

The proposed framework is based around two key concepts:

- *Enhancing the role of AEMO as national transmission planner (NTP)* to include a short, as well as a long, term focus on nationally coordinated planning by:
  - reviewing draft TNSP planning and investment test reports;
  - providing demand forecasts for use in transmission planning;
  - providing an expert independent advisory role; and
  - assuming the Last Resort Planning Power (currently with the AEMC).
- *Enhancing the role of TNSPs in driving coordination* by:
  - supporting increased consultation between TNSPs to identify and implement cross regional network investment options;
  - aligning the regulatory control periods for TNSPs; and
  - formalising TNSP input into the NTP's annual strategic planning report to ensure that both local and national perspectives are captured and reflected in the longer term planning process.

The proposed framework also includes the provision of robust price signals for use of the network through the introduction of a market-wide transmission pricing regime to be regulated by the AER and administered by AEMO.

The framework is intended to improve the national coordination of transmission planning and investment decision-making. It aims to provide more efficient arrangements for supporting investment across regional boundaries, lowering prices to customers over the long term. Increased transparency and coordination should also provide greater certainty to market participants, supporting their own investment and operational decisions.

These proposals essentially preserve existing institutional structures. However, the expansion of AEMO’s NTP role is predicated on a national entity providing a check and balance on jurisdictional TNSPs. Consequently, if implemented, this would be inconsistent with AEMO's current planning function in Victoria.

5.1 Introduction

Designing appropriate arrangements and incentives for efficient transmission planning and investment is among one of the most difficult challenges in energy market regulation. It requires coordinating the decisions of a number of different individual entities from both regulated businesses and the competitive sector.

Uncertainty surrounding demand patterns, generator investment decisions and generator output levels means that it is difficult to accurately plan a transmission network. There are therefore risks and uncertainties associated with the planning process, and the question is how to design regulatory and institutional arrangements that best allow for these to be managed.

This challenge is exacerbated by the lack of clear market signals for transmission planners on the demand for network services by generators under existing arrangements (which would persist under the non-firm access model). This issue would be addressed if the OFA model outlined in chapter 3 was adopted.

Planning and institutional arrangements will be particularly critical under the non-firm access model. Without market signals of the demand for network services to inform transmission network planning and investment decisions, greater reliance would be placed on regulatory mechanisms to ensure that TNSPs make efficient decisions.

Under the OFA model, while investment should largely be driven by generators requesting firm access, there will still be a residual need to ensure that load reliability standards are met. Therefore, a robust framework for transmission planning will still form part of the OFA model, albeit some modifications may be required.[95]

The remainder of this chapter is set out as follows:

- section 5.2 explains why there is a case for the existing planning arrangements to be strengthened;
- section 5.3 provides a holistic overview of the proposed framework for transmission planning and pricing;
- sections 5.4 and 5.5 describe the details of our proposals for enhancing the role of AEMO as the NTP and enhancing TNSPs' roles, respectively;
- section 5.6 describes the proposed market-wide transmission pricing mechanism;
- section 5.7 sets out the implications of the proposed framework, particularly in respect of the current institutional arrangements in Victoria; and
- section 5.8 addresses the options that were raised in the First Interim Report and not discussed in other parts of this chapter.

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95 Note that these modifications would require further consideration if the Commission were to recommend implementing the OFA model.

5.2 The case for change

5.2.1 Stakeholder views

Stakeholders have raised a number of concerns with transmission planning in submissions to this review. Their concerns have largely focussed on the fact that planning responsibilities are allocated on a jurisdictional, rather than a national, basis.

For example, in its submission to the First Interim Report, AEMO expressed concern that "there is no party responsible or accountable for maintaining a national grid, through the development and management of national flow paths".[96] AEMO also highlighted a number of previous reviews that it contended had reached similar conclusions.[97] A number of other stakeholders further echoed concerns about the coordination of planning across the NEM and, in particular, perceived inadequacies in the development of interconnectors between regions.[98]

The other major concerns highlighted by stakeholders in response to the First Interim Report were:

- suggestions that financial incentives on TNSPs relating to transmission investment are inappropriate because they tend to result in TNSPs either deferring investment or over-investing, depending on the point at which a TNSP is at in its regulatory control period. It was also suggested that TNSPs tend to favour network over non-network solutions;[99] and
- concerns that the Regulatory Investment Test for Transmission (RIT-T) is inconsistent with the National Electricity Objective (NEO) because ignoring wealth transfers from generators towards load is counter to the interests of electricity consumers.[100]

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96 AEMO, First Interim Report submission, p. 13.

97 Commonwealth of Australia, *Towards a truly national and efficient energy market*, 2002; Commonwealth of Australia, *Energy Reform: The Way Forward for Australia, A report to the Council of Australian Governments by the Energy Reform Implementation Group*, January 2007; Garnaut, Ross, *Garnaut Climate Change Review - Update 2011, Update Paper eight: Transforming the electricity sector*, 2011.

98 Victorian DPI, First Interim Report submission, p. 10; International Power, First Interim Report submission, pp. 30-32; MEU, First Interim Report submission, p. 3; Clean Energy Council, First Interim Report submission, p. 11; Alinta Energy, First Interim Report submission, p. 11; AEMO, First Interim Report submission, p. 3.

99 Victorian DPI, First Interim Report submission, pp. 10-11; Clean Energy Council, First Interim Report submission, p. 11; AEMO, First Interim Report submission, p. 52.

100 MEU, First Interim Report submission, pp. 6-7; Alinta Energy, First Interim Report submission, p. 11.

5.2.2 Commission's views

The Commission considers on the basis of evidence provided to date that there is no indication of a lack of inter-regional capacity being built. The Last Resort Planning Power investigations conducted by the Commission in both 2010 and 2011 found that TNSPs were planning to undertake RIT-T assessments of projects to augment inter-regional transmission capacity where appropriate.[101] Further, AEMO's initial analysis of a project to significantly expand interconnector capacity, NEMLink, suggests that substantial increases in capacity are unlikely to be economic.[102]

Nevertheless, we consider that there is scope to increase the national coordination of planning. While it is not clear that the current framework is delivering manifestly inefficient outcomes, there are some gaps. For example, a TNSP may not give full consideration to investment in other regions that could more efficiently meet reliability standards in its own region ("cross-regional investment").

The remainder of this chapter sets out our proposals for enhancing nationally coordinated transmission investment decision-making.[103] Note that because of the interlinked nature of transmission frameworks, these proposals have a number of implications for transmission reliability standards, economic regulation and network pricing.

In respect of concerns raised by stakeholders regarding the efficiency of financial incentives on TNSPs under existing regulatory frameworks, the Commission considers that this issue should be out of the scope of this review as it is being assessed through the Economic Regulation of Network Service Providers rule change request. It is, however, discussed to some extent where relevant.

Further, the Commission does not propose to reassess the case for altering the basis of the RIT-T.[104] Previous reviews have concluded that including wealth transfers away from generators in assessing the benefits of an investment is likely to negatively impact investment in generation, thereby damaging the long term interests of consumers. No evidence has been provided to suggest there is a case for revisiting this conclusion. We do, however, consider that changes could usefully be made to improve the transparency of any wealth transfers and competition benefits analysis. This is discussed in section 5.8.1.

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101 AEMC, *Investigation into the Exercise of the Last Resort Planning Power: 2010*, 10 November 2010, Sydney; AEMC, *Last Resort Planning Power Review: 2011 Decision Report*, 3 November 2011, Sydney.

102 AEMO, *2011 National Transmission Network Development Plan*, 9 December 2011, Chapter 6.

103 Many of these proposals are derived from work undertaken for the Commission by NERA Economic Consulting and Allens Linklaters. See: NERA Economic Consulting and Allens Linklaters, *Alternative Transmission Planning Arrangements: Ensuring Nationally Coordinated Decision-Making*, May 2012.

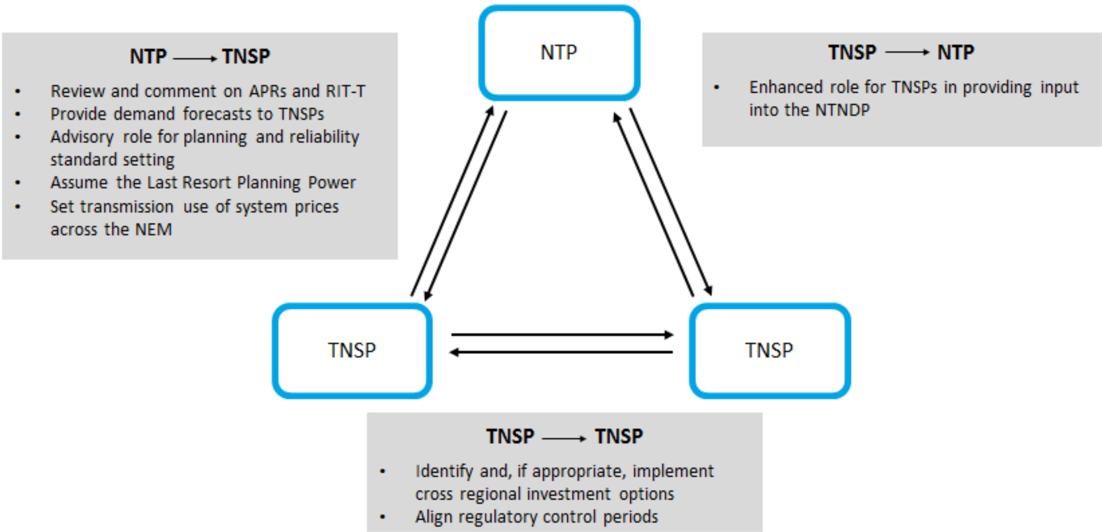
104 Note, this is based on the existing approach to generator access being maintained.

5.3 Overview of the proposed framework for transmission planning and pricing

The figure below provides an overview of the key components of the proposed framework for transmission planning and pricing in terms of the relationships between the NTP and TNSPs, and between TNSPs. These proposals include:

- an enhanced role for AEMO as NTP, particularly in terms of feeding into TNSP processes to provide strategic input and to promote coordination at a high level. This can be considered to include the administration of the new market-wide transmission pricing scheme; and
- enhancing the role of TNSPs, both in improving coordination between TNSPs and providing input into the NTP's National Transmission Network Development Plan (NTNDP).

Figure 5.1



5.4 Enhancing the role of the national transmission planner

5.4.1 Summary of proposals

The first element of the proposed framework is to enhance AEMO's role as NTP to facilitate increased coordination in transmission planning across the NEM. Currently the NTP has a long-term, strategic focus. While this is important, the Commission also sees a useful role for the NTP in the planning process to help drive consistency and coordination between TNSPs over the short to medium term. These additional functions would include:

- reviewing each TNSP's draft Annual Planning Report (APR) and RIT-T documentation and highlighting where TNSPs may be able to coordinate their investment, or where options in another region may help address an investment need (see section 5.5 for further discussion on this);

- providing demand forecasts to TNSPs to be used as a starting point for the forecasts used by TNSPs in their APRs and investment assessments;
- providing an expert and independent advisory role, including to the institutions involved in setting reliability standards for each jurisdiction; and
- taking on the Last Resort Planning Power (LRPP) currently held by the AEMC.

5.4.2 Review of TNSP planning documentation

Under the proposed framework, AEMO, in its role as NTP, would be given a formal role reviewing TNSPs' draft APRs and draft RIT-T documentation.

In undertaking this task, the NTP's main focus would be to highlight instances where it appears that:

- individual TNSPs are planning investments which have complementarities; or
- an investment need in a region could potentially be met by investment options in other regions.

Essentially, therefore, the NTP would be aiming to identify areas where coordination between regions is likely to be beneficial. This role would act as a check on a proposed new TNSP-TNSP consultation requirement in the NER (discussed in section 5.5.2), and would provide a further avenue for TNSPs to become aware of what others are planning. The NTP would flag with the TNSP that it should be consulting on a particular investment with neighbouring TNSPs. Since all APRs must be published by 30 June each year, the NTP would be able to review all the APRs at the same time and provide consistent comments across all jurisdictions.

This proposed role is consistent with the "additional advisory functions" that AEMO currently performs in South Australia. In particular, we understand that, although not explicitly specified in the NEL or NER, AEMO does comment on draft RIT-T documentation. This proposal would formalise that role across the NEM.

5.4.3 Provision of demand forecasts

It is also proposed that the NTP would produce a standardised set of demand forecasts for each region of the NEM, and provide these to TNSPs.[105]

TNSPs would be able to deviate from the NTP forecasts, either where it was more appropriate to use the forecasts supplied by registered participants[106] or where their

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105 AEMO has started to develop demand forecasts for all five regions of the NEM in advance of being specifically required to. See: AEMO, *National Electricity Forecasting*, Information Paper - December 2011, p. 3.

own local knowledge suggested that a revised forecast would be more appropriate. However, in such circumstances, a TNSP would have to explain how and why they deviated from the NTP’s forecasts.[107]

Allocating the role of demand forecaster to the NTP would ensure a consistent national approach in developing load forecasts and would remove any perceived conflict of interest associated with TNSPs undertaking this role. The AER may also benefit from having access to this alternative source of demand forecasts for network regulation determinations.

5.4.4 Provision of advice

As highlighted above, the expanded scope of the NTP's role means that it could usefully provide expert, independent engineering and planning knowledge to support decision-makers, such as the AER in relation to revenue regulation and compliance monitoring associated with the application of the RIT-T.

The NTP would also play an advisory role to the institutions involved in the setting of transmission reliability standards for each jurisdiction.

5.4.5 Last Resort Planning Power

Finally, we propose that the NTP should take over the Last Resort Planning Power (LRPP). The LRPP is currently held by the AEMC, and allows the Commission to direct registered participants to apply the RIT-T to potential transmission projects if they are likely to relieve forecasts constraints in respect of National Transmission Flow Paths which connect NEM regions. As previously noted, the Commission reports annually on the LRPP and, to date, we have not identified any concerns that TNSPs have not been conducting RIT-T assessments when it would have been appropriate to do so.

We consider that the NTP would be a more appropriate body to hold the LRPP than the AEMC. The NTP's planning expertise would provide it with the practical experience and knowledge to better discharge this function. Further, it is likely that administrative costs associated with the LRPP could be reduced, since it is more closely aligned with AEMO's core competencies. In addition, under the recommended framework the NTP would already be reviewing TNSPs' plans as part of its role in commenting on APRs. Consequently there are likely to be significant synergies in assigning the LRPP to the NTP.

However, we note that AEMO assuming the LRPP would be inconsistent with its current jurisdictional planning function in Victoria. Put simply, AEMO could not act as a "last resort" check on itself. This issue is discussed in section 5.7.

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106 Under clause 5.6.1 of the NER, registered participants are required to supply TNSPs with generation, market network service and load forecast information.

107 This is similar to current practice in South Australia.

5.4.6 Benefits of interaction between the NTP and TNSPs

The Commission considers that the new responsibilities for the NTP, combined with greater awareness by TNSPs of cross-regional investment options (discussed in the next section), will improve transmission planning coordination across the NEM, without having to significantly change the existing institutional structure.

Indeed, use of this institutional structure will provide a useful tension between TNSPs, which have a detailed knowledge and understanding of local conditions, and the NTP, which provides a more strategic perspective.

Consequently implementing this approach is likely to be significantly less costly and provide more benefits than some of the alternative options proposed in the First Interim Report, while achieving the desired outcome of strengthening the coordination of transmission planning and investment.

5.5 Enhancing the roles of transmission businesses

5.5.1 Summary of proposals

The second element of the proposed framework is to enhance the role of transmission businesses to facilitate increased coordination in network investment and to provide consistency across the NEM. This would involve:

- promoting the identification and implementation of network investment options which cross regional boundaries by introducing arrangements that support increased, and more transparent, consultation between TNSPs to achieve this;
- aligning the regulatory control periods for all TNSPs; and
- enhancing the role of TNSPs in providing input into the NTNDP to ensure that coordination between national and local issues occurs at the outset of the planning process.

The remainder of the section discusses each of these proposals in turn.

5.5.2 Cross-regional investment

The Commission considers there is a gap in existing frameworks whereby TNSPs have little incentive to investigate investment options in other regions that may meet their reliability requirements. For example, a reliability standard in NSW could potentially be met by an option undertaken in Queensland. A nationally coordinated planning approach would ensure that both intra-regional and cross-regional options were considered in determining the optimal investment.[108]

108 Processes are already in place for TNSPs to consider options to increase the inter-regional capacity of the network through the RIT-T process, where there are economic benefits from doing so.

NERA Economic Consulting was engaged to consider this issue, among others, and concluded that the gap could be addressed under the existing institutional structure in the NEM.[109]

Drawing from NERA's analysis, the Commission has concluded that a new requirement should be introduced into the NER for consultation between TNSPs in preparing APRs and undertaking investment assessments.

Under this approach, TNSPs would be required to consider whether there were options located either wholly or partly in other regions that could address an identified need. These options would be identified and developed through consultation with neighbouring TNSPs. Where a TNSP did not consider that options in other regions would meet an identified need, it would be required to explain the reasons for this. TNSPs would be required to make transparent any consultation that had taken place with other TNSPs. This process would be followed in developing APRs and in undertaking both RIT-T and non-RIT-T assessments.

To assist in this process, the NTP would be required to develop guidelines on assessing whether an investment need could be met by an investment in another region.[110]

If an option in another region was identified as being the preferred option, the TNSP in that region would need to agree to be the proponent of the investment. Without a proponent, the option could not be chosen as the preferred option. However, the transparent process by which preferred investment options are identified is expected to provide an incentive for neighbouring TNSPs to agree to be proponents where appropriate. The economic regulatory regime would also need to provide incentives (or at least not provide disincentives) for TNSPs in neighbouring regions to agree to be a proponent for cross regional investments.[111]

If moral suasion through the public planning process was insufficient, consideration may need to be given to whether obligations should be imposed on TNSPs to undertake cross-regional investment. This approach is not preferred initially, however, as it could result in an extended time period for undertaking the RIT-T assessment.

5.5.3 Align the regulatory control periods

At present, the regulatory resets for the TNSPs in the five NEM regions are staggered over a period of several years. This has led to concerns that the AER is not able to compare the various TNSP augmentation plans on a consistent basis.

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109 NERA Economic Consulting and Allens Linklaters, *Alternative Transmission Planning Arrangements: Ensuring Nationally Coordinated Decision-Making*, May 2012.

110 Such guidelines would be similar to the guidelines that AEMO is currently required to publish to assess whether a proposed transmission network augmentation is likely to have a material "inter-network" impact under clause 5.6.3(b) of the NER.

111 For further discussion on economic regulation refer to: NERA Economic Consulting and Allens Linklaters, *Alternative Transmission Planning Arrangements: Ensuring Nationally Coordinated Decision-Making*, May 2012, pp. 50-56.

The Commission considers that aligning TNSPs' revenue regulatory control periods is, in principle, likely to increase efficiency in transmission investment in a number of ways.

First, it would allow the AER to assess all TNSP proposals in a holistic manner. While the revenue allowances set by the AER do not determine which investments are ultimately made, the AER would be able to set allowances based on a consistent set of assumptions reflecting investment options that are the most efficient on a market-wide basis.

Aligning revenue resets is also likely to better allow for the implementation of the recommendation for improving cross-regional investment. This is because the AER would be able to allocate the required revenue for an investment directly to the TNSP in the other region.

Stakeholder views

In submissions to the First Interim Report, a number of stakeholders expressed support for this proposal, based on the benefits for transmission planning that would result.[112]

In particular, Grid Australia supported the intent of the proposal to better allow for the consideration of instances where investment on one TNSP's network can affect the transfer capability on a neighbouring TNSP's network. However, Grid Australia cautioned that the practical benefit of alignment would be limited by the different arrangements that apply in Victoria, which is a particular problem given that three of the four inter-regional boundaries in the NEM involve Victoria.[113]

The AER considered there would also be benefits from aligning revenue resets in terms of economic regulation.[114] Allowing the AER to consider each TNSP's regulatory proposal simultaneously could have advantages for economic regulation for two reasons. First, it allows the AER to make comparisons between cost forecasts and identify potential discrepancies. Second, a single consultation process which applies to all TNSPs helps ensure that the regulatory framework is consistent, where appropriate.

Conclusions

The Commission has previously suggested that there might be benefits in aligning transmission and distribution resets by NEM region. However, on balance, we consider aligning TNSP resets across the NEM to be the preferred option, because of

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112 Victorian DPI, First Interim Report submission, p. 10; AER, First Interim Report submission, pp. 9-10; Grid Australia, First Interim Report submission, pp. 24-25; InterGen, First Interim Report submission, p. 3; Hydro Tasmania, First Interim Report submission, p. 2; EUAA, First Interim Report submission, p. 6; Origin Energy, First Interim Report submission, p. 15; Infigen, First Interim Report submission, p. 4; Alinta Energy, First Interim Report submission, p. 17; TRUenergy, First Interim Report submission, p. 6.

113 Grid Australia, First Interim Report submission, p. 25.

114 AER, First Interim Report submission, p. 9.

advantages in terms both of promoting coordination in transmission planning and in economic regulation. We note that the AER agrees that "there are greater benefits associated with aligning resets by sector".[115]

A number of submitters to the First Interim Report expressed concerns with the implementation costs of realigning revenue resets and potential "peakiness" in the AER's workload on an ongoing basis.[116] We do not consider that the implementation costs need necessarily be substantial; however, there is likely to be a long lead time before all resets can be aligned by sector.

The Commission therefore endorses the alignment of revenue resets for TNSPs on an "in principle" basis. However, given that aligning regulatory control periods will have consequential effects for other sectors, further thought must be given to how this issue can be taken forward in a holistic manner and how any implementation costs could be minimised.

5.5.4 Input into the NTNDP

The Commission considers it appropriate to enhance the role of TNSPs in providing input to the development of the NTNDP. This would ensure that coordination between national and local issues occurs right at the outset of the planning process.

This input would be given effect through a working group, comprising TNSP representatives from all jurisdictions, which would comment on, and provide input to, the NTP's development and preparation of the NTNDP. This would complement the NTP's role in commenting on aspects of the TNSP's own planning and investment decision-making processes.

We understand that such a working group already exists, and that this recommendation would therefore largely represent a formalisation of existing practice.[117] However, in the same way that we consider it important for the NTP to have a codified role reviewing and commenting on jurisdictional investment planning processes, we also consider it appropriate for the role of TNSPs commenting on the NTNDP to be formalised. This should ensure that the different perspectives of the different parties involved in planning are appropriately captured and reflected throughout the process.

115 AER, First Interim Report submission, p. 10.

116 Victorian DPI, First Interim Report submission, p. 10; AER, First Interim Report submission, pp. 9-10; InterGen, First Interim Report submission, p. 3; Ausgrid, First Interim Report submission, p. 4; MEU, First Interim Report submission, p. 3; Origin Energy, First Interim Report submission, p. 15; ActewAGL, First Interim Report submission, p. 4; TRUenergy, First Interim Report submission, p. 6.

117 We understand that the NTNDP TNSP Reference Group meets 3-4 times a year. It is described by AEMO as "a working group of planning managers to coordinate the exchange of information for the National Transmission Network Development Plan (NTNDP) and keep AEMO and TNSPs informed on the progress of the NTNDP and Annual Planning Reports (APRs)". AEMO, *Industry Working Groups, Committees and Forums*, p. 8.

5.6 NEM-wide transmission pricing

The proposals set out in the previous two sections aim to provide robust arrangements that will promote efficient investment in the network on a cross-regional, as well as an intra-regional, basis. Similarly, the Commission considers it important that the transmission frameworks also promote the efficient use of the network between, as well as within, regions.

The Commission is therefore proposing the introduction of a market-wide transmission pricing scheme to give effect to consistent pricing signals across the NEM. These arrangements would be regulated by the AER and administered by AEMO.

Currently, the costs of all network augmentations in a particular jurisdiction are paid for by customers in that jurisdiction. Any customers in a neighbouring region that may benefit from such an augmentation are not exposed to any of the costs associated with it. The Commission has previously identified concerns that such "cross-subsidies could represent a potential barrier to the coordinated planning of transmission investment across regions".[118]

This issue is the subject of a rule change request from the MCE, which seeks to implement a system of inter-regional transmission charging referred to as "load export charging".[119] The Commission is due to publish a draft determination in February 2013. However, the rule change is limited in scope. In contrast, the Transmission Frameworks Review is a broader review that aims to set out a longer term vision for transmission pricing, and consequently has more scope to consider a holistic approach to the issue.

5.6.1 Proposed approach

Under a market-wide pricing scheme, all Transmission Use Of System (TUOS) tariffs would be determined across the NEM through a single charging mechanism.[120] Prices would be set on a consistent basis by a single entity using a single methodology. There would therefore be no differentiation between intra- and inter-regional prices.

The most important benefit of this approach is that it will enable customers to contribute to the costs of assets from which they benefit in other regions. It allows costs to be allocated proportionately to each customer, depending on their relative use of an asset in *any* region, through precise adjustment of TUOS tariffs for each connection point, enhancing cost reflectivity.

This is in contrast to the more limited options being considered in the inter-regional transmission charging rule change, where inter-regional charges would be uniformly

118 AEMC, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, Sydney, p. 42.

119 MCE, *Inter-regional Transmission Charging*, Rule change request, 15 February 2010.

120 For the avoidance of doubt, this would not alter the amount of revenue recovered by TNSPs, just the way in which it is recovered.

recovered from all customers within an importing region, as opposed to being targeted at the customers benefiting from the asset. Although this would allow for the transfer of revenues between regions, inconsistencies in intra- and inter-regional charging would be maintained, and distortions would remain in the cost-reflectivity of transmission prices.

Box 5.2: Ensuring full cost-reflectivity in transmission prices

AEMO, in its role as jurisdictional planner in Victoria, has recently consulted on the potential augmentation of the network in regional Victoria.[121] Although the identified need is load growth in Victoria, many of the options being considered would also alleviate network constraints in the Riverland region of South Australia.

Under current frameworks, the cost of the augmentation in Victoria will be entirely funded by Victorian customers. Although customers in the South Australian Riverland will benefit from the augmentation, they will not be exposed to any of its costs.

The Modified Load Export Charge being assessed in the inter-regional transmission charging rule change would mean that, to the extent the investment in Victoria benefited customers in the South Australian Riverland, the costs of this would be recovered from South Australia. However, the recovery of these costs would be uniformly smeared over all South Australian customers.

In contrast, with a single market-wide pricing scheme, these costs would be targeted at the benefiting customers in the Riverland through the precise adjustment of their TUOS tariffs. Customers in other areas of South Australia, which did not benefit from them, would not pay for the relevant assets in Victoria.

Unlike some forms of Load Export Charging, a national scheme would also allow customers to contribute to the costs of assets from which they benefit in non-adjoining regions.

Under the proposed approach, a national pricing model would be run by a central body, and TUOS tariffs calculated for each connection point across the NEM. The entity that determines the prices would not necessarily have to collect the charges, however: this responsibility could remain with TNSPs.[122] Although this proposal would represent a fundamental change to the existing arrangements, it is conceptually simple.

It should be noted that, if implemented, individual customers may see significantly different charges under the new regime, as compared to the status quo. However, these

121 AEMO, *Regional Victorian Thermal Capacity - Ballarat Supply*, Project Specification Consultation Report, 18 April 2012.

122 Payments would then be made between TNSPs to ensure that each collected its allowed revenue.

impacts may be able to be mitigated by phasing in the new, national tariffs. For example, this could be achieved in a similar way to the current restriction on tariffs changing by more than two per cent per annum as compared to the average charge.[123]

Other implementation costs would include the need to develop a national valuation model and cost allocation model.[124] There would also be a need to develop governance arrangements for the national pricing scheme (discussed below).

The implementation costs identified above are likely to be outweighed by the benefits associated with improving the cost reflectivity of transmission charging. Administrative efficiencies would also result, as prices would be set by a single body using a single methodology, as opposed to five parties using up to six methodologies.[125]

5.6.2 Governance arrangements

We consider that the market-wide scheme should be administered by AEMO. AEMO is well qualified to take on the role, being familiar with the transmission system across the NEM through its role as NTP. Its core competencies include calculating and settling financial transactions as market operator. It also uses Tprice (the software used by TNSPs to calculate TUOS charges) to set loss factors. Finally, allocating this role to AEMO would be consistent with the enhanced role for the NTP considered previously, in particular with regards to demand forecasting.

However, discharging this function would be inconsistent with AEMO's current role as planner and procurer of the transmission system in Victoria, as AEMO would be both determining and receiving charges. This issue is addressed in section 5.7.

We also consider that there would be a crucial role for the AER in regulating the market-wide process. It would be important that both customers and TNSPs could be confident that prices were set accurately.

The AER currently approves TNSP pricing methodologies as part of TNSP revenue resets. Under the proposed approach, there would be a single methodology, specifying the structure of charges and the means of deriving them, that AEMO would be bound by. Such a market-wide methodology could be governed by one of two options:

- AEMO could take over the role of developing the methodology from TNSPs, with the AER responsible for approving any changes. If TNSP revenue resets are aligned across the NEM, such amendments could be made prior to the

123 NER clause 6A.23.4(f).

124 In addition, consideration would need to be given to the allocation of Settlement Residue Auction proceeds, which are currently used to offset the costs of assets used predominately to support inter-regional flows. Retention of these arrangements would significantly diminish the cost-reflectivity of inter-regional or market-wide TUoS charges.

125 Under the Modified Load Export Charge being assessed in the inter-regional transmission charging rule change, TNSPs would use a harmonised, national pricing methodology for inter-regional charging while retaining each of their own methodologies for within-region charging.

commencement of TNSPs harmonised regulatory control periods or, alternatively, could be considered on an annual basis; or

- the methodology could be subsumed into the NER. This would allow any interested party, including customers and TNSPs, to propose changes to the methodology at any time.[126]

The first alternative represents the least change option. However, we also envisage that the AER would play a role in auditing both input data and final prices,[127] and would resolve any disputes between AEMO and TNSPs. There may be some inconsistency between this role and approving the underlying methodology, which would not be the case if the methodology formed part of the NER.

We would welcome the views of stakeholders with regards to the most appropriate governance arrangements for market-wide transmission pricing.

5.7 Implications of the proposed arrangements

The previous sections of this chapter have set out the Commission's proposals for improving transmission planning and pricing arrangements. However, this preferred framework has some fundamental implications, particularly for institutional arrangements in Victoria.

AEMO currently has several different roles in the electricity sector, including NTP, system operator and planner and procurer of the transmission network in Victoria. Under the Commission's recommended framework, the NTP's role would expand to include:

- providing a formal check and balance on TNSPs' planning and investment processes;
- taking over the LRPP; and
- calculating transmission prices across the NEM.

Each of these additional roles implies a national entity providing oversight and advice on the analysis and conclusions of jurisdictional TNSPs that is independent of those state-based planning processes. The different institutions involved in planning ensure that there is an appropriate tension and check on the planning role within the market. While this is consistent with the arrangements in most of the jurisdictions in the NEM, an inconsistency would arise in applying the arrangements in Victoria. This is because AEMO would essentially be providing a check and balance on its own work.

There are a number of options for resolving this inconsistency. For example, a new Victorian planning body could be established and assigned responsibility for

126 However, in practice, it seems unlikely that any changes would take effect within a financial year.

127 This role might be similar to the AER's approval of pricing proposals for electricity distribution under clause 6.18.8 of the NER.

jurisdictional planning in Victoria. However, the Commission considers that providing a consistent approach across the NEM is preferable, with the institutional arrangements in Victoria being aligned with those that apply elsewhere. This would imply assigning responsibility for jurisdictional planning to SP AusNet.[128]

The continuation of different arrangements in one or more parts of the NEM is likely to prevent the resolution of concerns that the transmission system will be developed on a fragmented basis rather than as an efficient national grid.

If these concerns are to be addressed, a single national approach is required. The Commission has concluded that the framework described in the previous sections is the most appropriate. Being able to apply this model consistently across the NEM will be important in ensuring the coordinated development of the national transmission network and maximising the overall efficiency of the transmission planning and investment decision-making frameworks.

In addition, the harmonisation of transmission arrangements across the NEM would result in lower transactions costs. Market participants (and regulators) currently must work within two very different sets of arrangements. This adds significant complexity – and therefore cost – to the arrangements. A single set of arrangements will therefore also increase efficiency in this regard.

Finally, as discussed further in section 5.8.2, the Commission considers that the current arrangements in Victoria, characterised by functional separation and a not-for-profit entity operating making investment decisions, are likely to result less efficient outcomes than would be the case with an integrated TNSP that is subject to financial incentives, provided those incentives are appropriately designed.

5.8 Options set out in the First Interim Report

The First Interim Report presented two sets of options for strengthening the planning and investment frameworks to promote improved coordination across the NEM. These included enhancements to the existing arrangements, as well as options for more significant reform. This section addresses the remaining options that were raised in the First Interim Report and not discussed in other parts of this chapter.

5.8.1 Enhancing existing arrangements

Five options for enhancing planning frameworks were identified in the First Interim Report. Of these, the alignment of TNSP regulatory resets has already been discussed. This section considers the four remaining options:

- implementing the national framework for transmission reliability standards for load;
- improving the consistency of APRs;

128 We note that it is likely that SP AusNet would need to consent to this change.

- increasing the transparency of the RIT-T; and
- reliability standards for interconnectors.

Implementing the national framework for transmission reliability standards

The First Interim Report highlighted the Commission's earlier recommendation that a national framework for transmission reliability standards for load should be introduced. This framework would be based on standards that are economically derived and deterministically expressed (a "hybrid" form of standards). The Commission has now been tasked with developing an implementation program.[129]

Submissions to the First Interim Report which addressed this issue were virtually unanimous that the national framework should be implemented.[130] A number of stakeholders also expressed support for the harmonisation of transmission planning arrangements across the NEM based on the South Australian approach, which includes a form of hybrid standards.[131]

However, in contrast, AEMO highlighted a number of concerns it holds with the South Australian approach.[132] Many of AEMO's concerns seem to relate to the specific way in which hybrid standards have been implemented in South Australia: for instance, the maintenance of past performance, which the Commission agrees should not be a principle that is adopted in the national framework. The Commission will consider these issues further when developing the implementation program for the national framework.

Improving the consistency of APRs

As discussed in the First Interim Report, analysis undertaken for the Commission in 2011 as part of our assessment of whether or not to exercise the LRPP suggested that transparency in the planning process may be increased if APRs were presented in a more consistent fashion.[133] The Commission sought views from stakeholders on the possible costs and benefits of requiring TNSPs to adopt a uniform approach to their APRs.

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129 MCE, *Transmission Reliability Standards Review*, MCE Response to AEMC Final Report, 16 November 2011.

130 AER, First Interim Report submission, p. 9; Grid Australia, First Interim Report submission, p. 24; InterGen, First Interim Report submission, p. 3; Hydro Tasmania, First Interim Report submission, p. 2; MEU, First Interim Report submission, p. 31; Government of South Australia, First Interim Report submission, p. 3; Infigen, First Interim Report submission, p. 4; Alinta Energy, First Interim Report submission, p. 17; TRUenergy, First Interim Report submission, p. 5.

131 Grid Australia, First Interim Report submission, p. 7; InterGen, First Interim Report submission, p. 2; Hydro Tasmania, First Interim Report submission, p. 3; MEU, First Interim Report submission, p. 3; ActewAGL, First Interim Report submission, pp. 3-4; Alinta Energy, First Interim Report submission, p. 20; TRUenergy, First Interim Report submission, p. 6.

132 AEMO, First Interim Report submission, p. 50.

Amongst stakeholders commenting, this option was universally supported.[134] These stakeholders considered that a uniform format would make it easier to compare APRs, facilitating comparative analysis. This was seen to be useful for the purposes of economic regulation as well as increasing predictability in the investment planning process for market participants.

Grid Australia noted that this option could be developed further into a formalised collegiate approach between the organisations with transmission planning responsibilities in the NEM.[135] Given the support from Grid Australia and other stakeholders, the Commission considers at this stage that improved coordination of APRs could be achieved without the need to formalise the requirement.

The Commission is interested in stakeholder views on whether the APRs for 2012 go some way to achieving greater consistency, noting that there has been a limited opportunity for TNSPs to implement any changes since the First Interim Report was published in November 2011.

Increasing the transparency of the RIT-T

The Commission proposed in the First Interim Report that transparency in the application of the RIT-T could be improved.[136] To achieve this we suggested that TNSPs would be required to estimate the economic impacts on market participants and customers that would be affected by a proposed investment, including wealth transfers. This would assist stakeholders in better understanding why some investment options are not taken forward, despite having potentially significant benefits for some stakeholders, due to the offsetting costs of other stakeholders.

The majority of submissions supported this enhancement.[137] However, some of the stakeholders noted that this support was subject to not increasing timeframes associated with undertaking a RIT-T.[138] The AER also noted that this requirement

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133 Intelligent Energy Systems, *Assessment of inter-regional congestion: report to the AEMC*, 3 November 2011, section 4.2.6. This report is available on the AEMC website at www.aemc.gov.au.

134 AER, First Interim Report submission, p. 9; Alinta, First Interim Report submission, pp. 17-18; Grid Australia, First Interim Report submission, p. 24; Hydro Tasmania, First Interim Report submission, p. 2; Infigen, First Interim Report submission, p. 4; InterGen, First Interim Report submission, p. 3; Government of South Australia, First Interim Report submission, p. 3; TRUenergy, First Interim Report submission, p. 5; Victorian DPI, First Interim Report submission, p. 10.

135 Grid Australia, First Interim Report submission, p. 26.

136 For further discussion on the RIT-T and this proposal, see: AEMC, *Transmission Frameworks Review*, First Interim Report, 17 November 2011, Sydney, pp. 134-135.

137 Victorian DPI, First Interim Report submission, p. 10; AER, First Interim Report submission, p. 9; Grid Australia, First Interim Report submission, p. 24; Infigen, First Interim Report submission, p. 3; Hydro Tasmania, First Interim Report submission, p. 2; Origin Energy, First Interim Report submission, p. 15; InterGen, First Interim Report submission, p. 3; Alinta Energy, First Interim Report submission, p. 17; TRUenergy, First Interim Report submission, p. 5.

138 AER, First Interim Report submission, p. 9; Origin Energy, First Interim Report submission, p. 15; Government of South Australia, First Interim Report submission, p. 3.

should not impose additional costs on TNSPs.[139] The Major Energy Users considered that the RIT-T should be modified to include customer benefits in its assessment (that is, wealth transfers).[140]

We note that the RIT-T specifically excludes the quantification of wealth transfers between market participants in determining the outcome of the test.[141] Wealth transfers on their own do not improve or reduce overall efficiency in the electricity market. Therefore, wealth transfers do not result in any change to the overall benefit to the market as a whole, relative to the base case, and so do not impact the preferred option under the RIT-T.

On the other hand, wealth transfers could have significant impacts on affected participants, including in the wider economy. Identifying which parties benefit or lose under proposed transmission investments would increase the understanding of RIT-T assessments for stakeholders. However, any changes to the RIT-T requirements should not impose disproportionate burdens on TNSPs, either through additional costs or time pressures. Additionally, we understand that it may be difficult to quantify wealth transfers. This is because most of the benefits that must be estimated under the RIT-T impact both consumers and generators and it would be difficult to allocate the total benefits between them.

For larger investments where market dispatch modelling is used to model the market benefits, such as where there are likely to be wholesale market impacts or effects on national transmission flow paths, a significant amount of information may be available. For example, market dispatch modelling provides data on spot price outcomes. However, it is not clear that the output from the market modelling would readily identify the parties that benefit and lose.

Moreover, in other instances (e.g. investments to meet local reliability standards where there is not an impact on the wholesale market) a TNSP may not even use market dispatch modelling to quantify benefits and costs and so significantly less quantitative information is available. In the absence of this, it is difficult to see how wealth transfers could be identified. For example, a simplified approach may be used to estimate the material benefits associated with reducing network losses. These benefits accrue to two different parties – generators pay for losses to the Regional Reference Node, whereas customers pay for losses from then on. While simplified modelling would calculate these benefits in total, it would not allow easy identification of how much each party benefits. Additionally, requiring quantification in this circumstance would likely impose additional costs on TNSPs, and potentially delay timeframes.

The Commission would therefore be interested in stakeholders' views as to how the identification of these wealth transfers would occur. For example, whether TNSPs could readily model and quantitatively identify these participants as part of their RIT-T

139 AER, First Interim Report submission, p. 9.

140 MEU, First Interim Report submission, p. 31.

141 AER, Regulatory Investment Test for Transmission, June 2010, clause(6)(a).

assessments, or whether TNSPs could provide enough information to participants through a qualitative discussion of these benefits.

Interconnector reliability standards

The First Interim Report noted some stakeholder and commentator concerns that existing processes for investment in interconnector capacity is less likely to result in augmentations being undertaken compared to work required to meet reliability obligations within a region.[142] To address this issue, International Power proposed that the NTP set a level of interconnector capability and TNSPs be assigned responsibility for maintaining that level. International Power considered this approach would give interconnector capacity and reliability equal status with jurisdictional reliability planning standards.[143]

In submissions to the First Interim Report, there were mixed views on the appropriateness of setting interconnector reliability standards. Some stakeholders agreed that this approach would place inter-regional capacity on the same basis as intra-regional reliability and, further, that it would facilitate inter-regional trade.[144] Supporters further considered that the benefits of increased inter-regional trading would outweigh any costs associated with the approach.[145]

Other stakeholders were concerned that setting reliability standards for interconnectors that must be maintained would lead to inefficient over-building.[146]

Overall, those stakeholders that commented on this option supported its further consideration.[147] The AER also highlighted the linkages to its own consultation on incentives to encourage TNSPs to maintain the capacity of the existing network.[148]

Maintaining interconnector capacity forms part of the proposed OFA model. As explained further in section 3.9, under this model, TNSPs would be required to ensure there was sufficient capacity to provide the level of agreed interconnector access on an ongoing basis. Non-firm generators constraining off interconnector flows would pay compensation, such that interconnector users were kept financially whole. Interconnector capacity could not be degraded by releasing it to new firm generators.

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142 International Power, Directions Paper submission, p. 11; Garnaut, Ross, *Climate Change Review - Update 2011*, Update Paper eight: Transforming the electricity sector, pp. 29-30. For further discussion, see: AEMC, *Transmission Frameworks Review*, First Interim Report, 17 November 2011, Sydney, pp. 138-139.

143 International Power, Directions Paper submission, p. 12.

144 Alinta, First Interim Report submission, p. 19; International Power, First Interim Report submission, pp. 45 and 55; TRUenergy, First Interim Report submission, p. 6.

145 TRUenergy, First Interim Report submission, p. 6.

146 Grid Australia, First Interim Report submission, p. 25; MEU, First Interim Report submission, p. 26.

147 AER, First Interim Report submission, p. 9; Grid Australia, First Interim Report submission, p. 25; MEU, First Interim Report submission, pp. 26 and 31; Origin Energy, First Interim Report submission, p. 15.

148 AER, First Interim Report submission, p. 9.

Under the OFA model, market participants would be able to seek to procure additional inter-regional access rights. Where a TNSP identifies a potential inter-regional expansion project, market participants would be able to express their interest by submitting bids. An inter-regional expansion project would then proceed if sufficient bids were received to recover the cost of the investment. This approach provides a market-based signal for investment in new interconnector capacity where it is valued by users of that capacity.

In contrast, it is not clear on what basis the NTP would set a level of capacity for interconnectors under International Power's proposed approach. The Commission considers that, under the status quo, the RIT-T provides an appropriate basis on which to assess the need for inter-regional investment. Further, we consider that this test is being applied appropriately, evidenced by current investigations on the need to upgrade capacity on every interconnector.

The Commission considers that the proposals for strengthening the planning arrangements, combined with the existing RIT-T process, should provide an suitable framework under the non-firm access model for promoting efficient interconnector capacity.

5.8.2 Options for more significant reform

Four options for significant reforms to planning arrangements were proposed in the First Interim Report, including:

1. enhancing coordination of the NTNDP and APRs;
2. a harmonised regime based on the South Australian arrangements;
3. a single NEM-wide transmission planner and procurer; and
4. a joint-venture planning body established by TNSPs.

The discussion below briefly summarises stakeholder views on these options and explains how they relate to the proposed framework or why the Commission is not recommending taking the option forward, as appropriate.

Coordination of planning documents

The recommended framework set out in sections 5.4 and 5.5 combines elements of, and extends, options 1 and 2. In particular, the proposed role for AEMO builds upon its current planning functions in South Australia. These two options garnered the most support in submissions to the First Interim Report and they were viewed by some as complementary measures.

Coordinating APRs and the NTNDP was generally seen to be beneficial, although there were concerns that the benefits might be relatively limited.[149] There were also concerns about how disagreements might be resolved if TNSPs and the NTP were required to sign-off on each other's planning documents, and how long this might take.[150] The proposed framework does not impose this sign-off requirement, but formalises greater coordination and discussion between the NTP and TNSPs, as well as between TNSPs.

Grid Australia was concerned about the planner/procurer model continuing in Victoria on the basis that there is significantly less oversight and scrutiny of investment plans and decisions in that state, and that there is no evidence that the competitive tendering model reduces costs compared to the regulatory model.[151] This issue is addressed in section 5.7.

Implementing the South Australian arrangements

Supporters of a harmonised regime based on the South Australian arrangements cited the following reasons:

- consistency of arrangements would promote efficiency in inter-regional investment and would benefit users;[152] and
- use of financial incentives encourages efficiency.[153]

There was also significant support for a party other than TNSPs undertaking demand forecasting.[154] Grid Australia considered that this would be a matter for jurisdictional governments to consider,[155] but supported independent oversight of TNSPs' demand forecasts by AEMO.[156]

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149 ActewAGL, First Interim Report submission, pp. 3-4; AER, First Interim Report submission, p. 10; Alinta, First Interim Report submission, p. 19; Infigen, First Interim Report submission, p. 4; InterGen, First Interim Report submission, p. 2; Hydro Tasmania, First Interim Report submission, p. 3; MEU, First Interim Report submission, p. 27; Queensland Government, First Interim Report submission, p. 2; Government of South Australia, First Interim Report submission, p. 3; TRUenergy, First Interim Report submission, p. 6.

150 Alinta, First Interim Report submission, pp. 19-20; South Australian Government, First Interim Report submission, pp. 3; TRUenergy, First Interim Report submission, p. 6.

151 Grid Australia, First Interim Report - Supplementary Submission, pp. 4-5.

152 Ausgrid, First Interim Report submission, p. 2; Grid Australia, First Interim Report submission, p. 7; Hydro Tasmania, First Interim Report submission, p. 3; TRUenergy, First Interim Report submission, pp. 6-7.

153 Alinta, First Interim Report submission, p. 20; Grid Australia, First Interim Report submission, p. 27; MEU, First Interim Report submission, p. 28; Government of South Australia, First Interim Report submission, p. 3.

154 AER, First Interim Report submission, p. 11; Alinta, First Interim Report submission, p. 20; Infigen, First Interim Report submission, p. 4; InterGen, First Interim Report submission, p. 2; MEU, First Interim Report submission, p. 28; TRUenergy, First Interim Report submission, p. 7.

155 Grid Australia, First Interim Report submission, pp. 8 and 31.

156 Grid Australia, First Interim Report – supplementary submission, p. 8.

In contrast, as previously noted, AEMO was concerned that the South Australian arrangements are inefficient, particularly the way in which hybrid standards have been implemented.[157] Some stakeholders considered that transmission planning arrangements outside of Victoria were less likely to result in efficient outcomes. This is discussed below in the context of the proposal for a single NEM-wide planner and procurer model.

The Commission considers that, broadly, the South Australian approach to transmission planning is an appropriate basis from which to develop a harmonised NEM-wide approach to transmission planning. The proposed framework therefore includes an enhanced role for the NTP across the NEM, implementing many of its existing functions in South Australia in other jurisdictions.

A single NEM-wide transmission planner and procurer

AEMO, the Victorian DPI, the Clean Energy Council and Pacific Hydro supported implementing the Victorian planner/procurer model across the NEM.[158] These stakeholders were concerned that planning arrangements outside of Victoria:

- do not allow an appropriate response to generator entry;[159]
- will not result in coordinated and efficient inter-regional investment;[160]
- place incentives on TNSPs to delay investment and favour network over non-network solutions;[161] and
- do not capture the benefits of competitive service provision.[162]

Many other stakeholders raised concerns with the NEM-wide planner and procurer model and the current Victorian arrangements, including:

- an inefficient separation of responsibilities;[163]
- the adverse impact of the lack of financial incentives on decision making;[164]
- a lack of accountability and of checks and balances;[165]

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157 AEMO, First Interim Report submission, pp. 48-50.

158 AEMO, First Interim Report submission, p. 50; Clean Energy Council, First Interim Report submission, p. 11; Pacific Hydro, First Interim Report submission, p. 5; Victorian DPI, First Interim Report submission, pp. 10-11.

159 Victorian DPI, First Interim Report submission, pp. 10-11.

160 AEMO, First Interim Report submission, pp. 12-14; MEU, First Interim Report submission, p. 29; Victorian DPI, First Interim Report submission, p. 10.

161 AEMO, First Interim Report submission, p. 18; Clean Energy Council, First Interim Report submission, p. 11; Victorian DPI, First Interim Report submission, p. 11.

162 AEMO, First Interim Report submission, p. 19; Pacific Hydro, First Interim Report submission, p. 5.

163 Grid Australia, First Interim Report submission, pp. 8, 27-28.

164 Grid Australia, First Interim Report submission, p. 27; MEU, First Interim Report submission, p. 29.

- a loss of local knowledge or focus;[166] and
- the impact on connection arrangements.[167]

On balance, the Commission considers that a single NEM-wide transmission planner and procurer is unlikely to be efficiency enhancing. There are two key reasons for this.

First, the Commission considers that financial incentives are likely to provide the most robust and transparent driver for efficient decision-making. This is discussed in Box 5.3 below. Consequently, a not-for-profit decision maker is not our preferred option.

Second, and consistent with the use of financial incentives, the Commission supports arrangements whereby the owner and operator of a network is also responsible for planning and investment decisions. A single entity is better placed to trade off the relative costs and benefits of operational and investment decisions. This is likely to

Box 5.3: Advantages of for-profit TNSPs

The Commission considers that financial incentives are likely to provide the most robust and transparent driver for efficient decision-making. Efficient outcomes can best be promoted by aligning the commercial incentives on businesses with the interests of consumers. This view that financial incentives are likely to lead to more efficient outcomes is widely held (and practised) by regulators internationally as well as in Australia. All entities are subject to incentives: financial incentives provide an understandable and transparent approach to influencing behaviour.

While there may be some inefficiencies present in the existing regulatory framework,[168] this is not an indication that financial incentives do not work; rather, the existing frameworks can be improved to better align TNSP incentives with the interests of consumers. This is being pursued through the Economic Regulation of Network Service Providers rule change process.

The Commission further considers that there are likely to be drivers for financial incentives to play an increasing role in the economic regulation of TNSPs, for instance, the availability incentive scheme under the OFA model set out in chapter 3. While this scheme would, initially at least, focus on TNSPs making assets available in operational timeframes, this is inextricably linked to earlier investment decisions in terms of the specification and configuration of assets.

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165 AER, First Interim Report submission, p. 11; Ausgrid, First Interim Report submission, pp. 1-2; Grid Australia, First Interim Report submission, p. 28.

166 Alinta, First Interim Report submission, p. 20; Ausgrid, First Interim Report submission, p. 2.

167 ActewAGL, First Interim Report submission, p. 5; Alinta, First Interim Report submission, p. 20; Grid Australia, First Interim Report submission, p. 30; Infigen, First Interim Report submission, p. 4; Origin Energy, First Interim Report submission, p. 15.

168 AEMC, *Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services*, Directions Paper, 2 March 2012, Sydney, p. 34.

result in more efficient outcomes than where these functions are separated, such as in a "planner and procurer" model, where operational and investment decisions are made in isolation.

The combination of a single, for-profit entity that is responsible for both investment in, and operation of, a network creates an important link between service performance accountability, risk and reward that should drive efficient overall outcomes. A single entity responsible for these functions is better placed to manage the risks associated with the decision-making process as it has more control over outcomes that affect network performance. An ability to manage risks is a pre-requisite for bearing accountability for service performance. Financial incentives in the form of rewards and penalties can then be applied to ensure that service performance is consistent with the interests of consumers of electricity.

The separation of functions is required in Victoria to permit competitive tendering. Taking account of the disadvantages of separation, the Commission does not consider that any compelling evidence has been provided to demonstrate that competitive tendering will result in more efficient outcomes. We note that it is common practice for TNSPs to outsource construction activities. There is therefore competitive tendering by all TNSPs, to some extent, to ensure that investments are constructed efficiently.

The incumbent TNSP in Victoria has won the vast majority of contested works. Further, even contestable projects require a proportion of non-contestable work to be undertaken.[169] Of the first five contestable projects in Victoria, entities other than SP AusNet were awarded two projects at a total value of approximately $40 million. The remaining three projects were awarded to SP AusNet, in addition to non-contestable work associated with each of the five projects, totalling approximately $90 million.[170] SP AusNet has since won all of the ten subsequent tenders.

Finally, there are some significant costs associated with this approach. These costs include the direct costs to AEMO and tenderers of tendering, which have been estimated as being around five per cent of the overall cost of a contestable project.[171] As noted above, the functional separation that results from the tendering approach is also likely to impose indirect costs and increase risk. Where an investment decision is taken in isolation, there is a risk that overall costs will not be minimised. Lower investment costs might result in increased operational costs, and therefore higher costs in total.

The separation of functions also adds significant complexity to the connections process. Although AEMO's recent Victorian Connections Initiative aimed to improve the

169 Associated non-contestable project work undertaken SP AusNet represented approximately 17 per cent of the value of the value of the Rowville Transmission Facility and approximately 200 per cent of the value of the SNOVIC upgrade undertaken by TransGrid. See: SPI PowerNet, *Submission to Essential Services Commission, Electricity Transmission Augmentation Guidelines*, August 2003, p. 12.

170 SPI PowerNet, *Submission to Essential Services Commission, Electricity Transmission Augmentation Guidelines*, August 2003, p. 12.

171 SPI PowerNet, *Submission to Essential Services Commission, Electricity Transmission Augmentation Guidelines*, August 2003, p. 15.

process, the need for connection applicants to negotiate with AEMO, SP AusNet and potentially a new entrant TNSP adds inherent complexity. Allowing proponents to negotiate directly with a single TNSP is likely to mitigate some of the concerns expressed by stakeholders about connections in Victoria.[172]

Consequently, the Commission does not consider that there is any compelling case for retaining the current arrangements, including competitive tendering, in Victoria.[173]

A joint-venture planning body

Developing a joint-venture planning body comprising all TNSPs garnered the least support of the options canvassed in the First Interim Report. While there was some recognition of the potential benefits, such as allowing national coordination while retaining local knowledge,[174] concerns were raised about:

- whether a joint-venture between so many disparate parties would be workable;[175] and
- ongoing duplication of resources.[176]

Consequently, there was no support for the immediate implementation of this option, although some stakeholders noted it could be considered in the future.[177]

Following further analysis, including that commissioned from NERA Economic Consulting and Allens Linklaters,[178] the Commission has concluded that a joint-venture planning body is likely to be difficult to implement in practice. Further, the benefits of a joint-venture body can be achieved more effectively by drawing on and enhancing existing institutional arrangements, as set out in sections 5.4 and 5.5 above.

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172 See chapter 6 for further discussion on stakeholder concerns about the connection process and how these might be addressed.

173 We note that AEMO is proposing to move from a "Build, Own, Operate" regime to a "Build, Own, Transfer" model, with the aim of stimulating greater competition in the tender process. This would be very similar to the tendering process undertaken by other TNSPs, but with the added indirect costs that result from the separation of functions. Such a development would not therefore alter our conclusion that these arrangements should not be retained in Victoria.

174 Grid Australia, First Interim Report submission, p. 29.

175 Alinta, First Interim Report submission, p. 20; MEU, First Interim Report submission, pp. 3, 20-21.

176 AER, First Interim Report submission, p. 11.

177 ActewAGL, First Interim Report submission, p. 5; MEU, First Interim Report submission, p. 32.

178 NERA Economic Consulting and Allens Linklaters, *Alternative Transmission Planning Arrangements: Ensuring Nationally Coordinated Decision-Making*, May 2012.

6 Improving the connection framework

Box 6.1: Summary of this chapter

This chapter sets out the Commission's proposals for improving the arrangements for connecting to the transmission system.

Improving the efficiency of the connection process

We propose measures to enhance transparency in the connection process, including requirements to publish a standard contract and design standards for connection assets, and to provide detailed cost information to applicants.

Connecting parties should also have a greater role in the tender process for construction of connection assets. We propose that all competitive tender responses received by TNSPs should be available to applicants, and TNSPs should be required to demonstrate consideration of the applicant's priorities in selecting a contractor.

Extensions

The National Electricity Rules are currently ambiguous in their treatment of extensions. TNSPs generally view the provision of extensions as a non-regulated service, outside the scope of the rules. The Commission does not consider this was the intention of the rules, and considers that all transmission assets owned by TNSPs should be covered by the provisions in the rules.

The service delivery chain for the provision of an extension consists of a number of elements. While workable competition exists for some of these elements, such as design and construction of the assets, incumbent TNSPs benefit from economies of scale, scope and experience in a number of elements, and are in most cases the only party able to provide an "end-to-end service" for the provision of an extension. Consequently, we consider it is appropriate that some form of light-handed regulation should apply to TNSP provision of extensions.

We recommend that the rules are clarified to clearly allow a connecting party to issue a tender for the provision of an extension, or elements of that provision. A TNSP can participate in such a tender, but if requested by a connecting party, must provide an extension as a negotiated transmission service. In order to avert competition concerns, controlling ownership of both generation and shared transmission assets should be prohibited.

Rules clarification

The Commission is proposing a scheme for clarifying and simplifying the rules relating to connections. The key principle behind the proposed scheme is that the only distinction in the rules between connection assets and transmission network assets should be in who funds those assets.

6.1 Introduction

During the course of the review, a number of stakeholders have expressed significant concerns with the arrangements for connecting to the transmission system. We consider that improvements could be made to transmission frameworks in this regard, and this chapter discusses our proposals.

The chapter is structured as follows:

- section 6.2 considers the efficiency of the connection process, and incorporates contestability in connections, the negotiating framework and the dispute resolution process. Our proposals in these three areas are interdependent and need to be considered together;
- section 6.3 sets out the issues and our proposals in relation to the regulatory framework for extensions; and
- section 6.4 sets out the principles for a proposed revision of the rules relating to connections and extensions, which we believe would provide greater clarity.

In sections 6.1 - 6.3 of this chapter, we refer to connection assets to mean the substation and any asset between the substation and the substation fence. We refer to extensions to mean lines and other equipment between the substation fence and the generator (or consumer) facility. However, in section 6.4 we propose for consultation revisions to the rules, including to the definitions for connection-related services and assets.

6.2 Improving the efficiency of the connection process

6.2.1 First Interim Report

In the First Interim Report we set out a number of issues that have been identified in relation to the provision of connection services by TNSPs. These included a lack of clarity regarding how connections are currently regulated, the rights that generators and other transmission users have when negotiating a connection to the national grid and the relationship between contestability and economic regulation for the provision of connections and extensions.

We put forward three proposals for consultation in response to those concerns:

- enhancements to the dispute resolution provisions that currently apply to negotiated transmission services;
- strengthening the negotiating framework that applies to negotiated transmission services, including measures to increase transparency and potentially specifying the return that TNSPs are entitled to for providing these services; and

- migrating transmission services that are required for the connection of generators and other transmission users to the national grid from negotiated transmission services to prescribed transmission services.

The following section explains that, in response to submissions to the First Interim Report and further investigation, we propose to pursue the second of these proposals.

6.2.2 Commission proposals

The Commission proposes the following package of measures to **enhance transparency of the connection process**:

- a requirement in the rules for TNSPs to publish:
  - a standard connection contract,
  - design standards and philosophies for equivalent assets used to connect DNSPs as a prescribed service;
- a requirement in the rules for TNSPs to provide to connection applicants:
  - detailed cost, assumption and calculation information, including supporting evidence; and
- a power for AER to develop (and enforce) guidelines on specific information TNSPs should provide to connection applicants.

The Commission also considers that connecting parties should have a **greater role in the process of tendering for connections**, so that they have confidence they are benefiting from the contestability that exists in construction of connection assets. In order to facilitate this, we propose that the rules are amended to explicitly require TNSPs to:

- provide to connection applicants all responses from contractors to the TNSP's tender for construction of connection assets;
- provide to connection applicants detailed business cases for their decisions on choice of contractors; and
- demonstrate they have considered the applicant's preferences when selecting a contractor.

Enhancing transparency in the connection process

When negotiating with a TNSP to connect their facilities to the transmission system, connecting parties currently have little confidence that their connection is provided at competitive cost, to efficient scale and specification and within reasonable timeframes. In responses to the First Interim Report, generators and other parties called for increased transparency of cost and other information to help strengthen their negotiating position.[179]

Information to be published

The Commission proposes that TNSPs be required to publish their design standards and philosophies for connection assets which are used in connecting Distribution Network Service Provider (DNSP) loads (which is a prescribed service). The Commission understands that assets used for connecting generators and large loads are built to meet the same core technical design standards and criteria as those used to connect DNSPs under a prescribed service.[180] Prescribed services have a much higher degree of regulatory oversight than negotiated services, as their cost is subject to approval by the AER. This should provide confidence to connecting parties that the choice and design of assets used for those services are relatively efficient.

To complement this, the Commission considers it would benefit connecting applicants if TNSPs published the terms of a standard connection contract. The availability of this general information would give applicants, and potential applicants, an indication of what their requirements and obligations are, and would allow for comparison across TNSPs to give applicants some confidence that their individual connection is broadly in line with similar connections across the NEM. It would also place them in a stronger position to start negotiating, and to request information from the TNSP where designs or contract terms are materially different from standard.

This standard contract should also act as a default option, available to all connecting parties where they request it. While some elements of an agreement will always have to be left open to negotiation for each individual connection, TNSPs should make it clear which clauses of the contract can apply generally across all connections, which clauses can apply to all connections of a certain type (for example, all generators of a certain size), and which can only be agreed in relation to a specific connection.

The rules could specify that this information be published on a regular (e.g. annual) basis, or could require TNSPs to ensure that it always reflects their current approach.

Information to be provided to connecting party

Since all connections are bespoke to some extent, applicants also need specific information relating to their connection. There is mixed evidence on the level of information that is currently provided, with some generators claiming the information they receive contains little or no detail beyond a single cost figure. We propose that the

179 Private Generators Group, First Interim Report submission, p. 5; CitiPower and Powercor, First Interim Report submission, p. 4; Victorian DPI, First Interim Report submission, p. 13; Government of South Australia, First Interim Report submission, p. 4; TRUenergy, First Interim Report submission, p. 9.

180 In a report to the Commission published alongside this report, Deloitte Touche Tohmatsu advises that "in terms of their functional specifications, transmission connection assets are highly similar (if not identical) to prescribed assets used to connect distributors." See: Deloitte, *Feasibility of implementing contestability within the transmission connection arrangements*, 9 July 2012, p. 42.

rules specify in more detail the types of information that TNSPs must provide to an applicant on request.

The aim of the negotiating framework is to produce outcomes similar to those that would occur in a competitive environment. Hence we consider that TNSPs should not be required to provide any greater level of cost information than would be expected to be provided by a contractor responding to a competitive tender.

The Commission considers that the rules should specify examples of information it expects to be provided under this provision. We welcome feedback from generators and other users on what information they would expect to receive in order to make an informed decision on reasonable costs.

Back-up power for AER

In order to help enforce the above requirement, we also propose that a power be conferred on the AER to develop and enforce guidelines on the specific information that should be provided.

It would be for the AER to decide exactly when and how to use this power. We anticipate that the AER would monitor the information that is provided by TNSPs under the new requirements for a period of time, and only enforce guidelines if it considers that the information provided falls short of the level of information that would be expected in response to a competitive tender for the same work. The guidelines could be enforced for individual TNSPs or across the board.

Enhancing the role of connection applicants in the process of tendering for connections

Contestability currently exists in the construction of connection assets. TNSPs rarely carry out the construction work "in-house", preferring to tender for this element of the provision of a connection. However, the benefits of this contestability are either not passed onto or not apparent to connecting parties, who typically are not involved in the tender process.

We consider that connecting parties should have a greater involvement in this tender process, because the way it is carried out and the decision on which contractor is selected can have a material impact on the cost and design of their connection, and the time taken for construction. In order to facilitate this, we propose that all competitive tender responses received by the TNSP should be available to participants where requested, and that TNSPs' business cases for decisions when choosing contractors should be shared with connection applicants.

In addition, we consider that TNSPs should be required to demonstrate that they have considered the preferences and priorities of the connecting applicant when selecting a contractor, and this should be reflected in the business case for the decision.

The final decision on which contractor to employ should rest with the TNSP, since they are responsible for security and reliability of the shared network, which could be impacted by the design and construction of the connection. However, this decision should not be taken independently of the connecting party's requirements.

Many generators may be willing to pay a higher cost for work to be completed earlier. Where more than one tender meets the minimum standards required by the TNSP (and this should be more transparent under the proposals above), the connecting party should have the ability to express that preference. Where the TNSP’s choice does not match that preference, the TNSP should be required to provide written explanation in the business case for its decision to justify its choice. This should be made available to the connecting party, who may choose to enter into dispute resolution if it is not satisfied its preferences were sufficiently considered.

We recognise that a similar process is possible in practice now, as a connecting party could request a variation to a Connection Agreement, to incorporate a higher price, or flexible terms could be negotiated initially. However, as described above, we consider that the TNSP has a stronger position in the negotiation, and that specifying in the rules that it must consider the connecting party's preferences is an appropriate measure to strengthen the party's negotiating position.

Is increased contestability feasible?

The Commission considers that competition for services will lead to the most efficient outcomes, where it can be effectively implemented. However, the Commission's view is that there are inherent conflicts which mean contestability in ownership or operation of connection assets is unlikely to be efficient. The incumbent TNSP needs to be closely involved in the design and construction in order to ensure the security and reliability of the shared network. Liability lies with the TNSP, and transferring that liability would involve significant transaction costs which are likely to outweigh any benefit from increased contestability.

There is an inherent tension between the desire for a connecting party to minimise its costs of connecting to the transmission system and the advantage to a TNSP of having the most reliable and long-lasting transmission assets possible.

With the current institutional arrangements in place, there are effectively two basic models which may facilitate contestability in the provision of connections:

- the "build, own, transfer" model, where the TNSP is directly involved in the design, construction and commissioning to ensure reliability standards are upheld, and ultimately owns the assets; or
- the "build, own, operate" model, where the connection applicant oversees the construction and commissioning of the connection assets, retains ownership after construction and takes responsibility for ongoing asset performance.

Box 6.2: Current contestability arrangements

The NER does not currently mandate which assets or services should be considered contestable. The definition of "contestable" in Chapter 10 of the NER provides only limited guidance, stating that a transmission service is contestable if the laws of the relevant jurisdiction permit it to be provided by more than one TNSP "as a contestable service or on a competitive basis".

TNSPs appear to consider that the ownership of transmission assets outside of the fence of the substation on the shared transmission network is contestable. TNSPs consider that, on this basis, any such assets should not be subject to any form of economic regulation, even if provided by the TNSP.[181] However, there is a lack of clarity in the frameworks as to whether this is the most appropriate demarcation. It is also not clear whether the contestable construction of assets within the substation fence is permitted. While this has occurred in the past, TNSPs now express "serious concerns" about allowing this.[182]

In Victoria, the contestability arrangements are different. The shared transmission network is planned and procured by AEMO and a project will currently be procured through competitive tendering if:[183]

- the capital cost of the augmentation is reasonably expected to exceed $10 million; and
- it can be provided as a distinct and definable service and will not have a material adverse effect on an incumbent network asset owner.

This means that elements of the shared network required to facilitate a connection (such as the substation on the shared network) in Victoria may be competitively procured by AEMO. In addition, clause 8.11.8 of the NER appears to give connection applicants the ability to construct such assets without AEMO conducting a competitive tender.

The build, own, transfer model would effectively result in the same outcomes as under the current arrangements, as construction is procured competitively, and the asset is ultimately owned by the TNSP. The potential advantage of this model over current arrangements is that the costs of design and construction would be more transparent to the connecting party, who would also directly benefit from the efficiencies of the competitive procurement. However, we consider the Commission's proposals above would help to achieve these advantages without the transaction costs involved in asset transfer.

The Commission stated its view in the First Interim Report that neither the operation and maintenance of a new substation nor the connection of a user to a substation can

181 Grid Australia, *Categorisation of Transmission Services Guideline*, August 2010, section 3.2.

182 Grid Australia, First Interim Report submission, p. 33.

183 NER clause 8.11.6(a).

be provided on a genuinely contestable basis.[184] This is because the management of a substation affects electricity flows to users on the shared network, and it is the TNSP that has responsibility for security and reliability of supply on the shared network. Submissions to the First Interim Report suggested construction of substations could be treated separately however, and may be contestable.[185]

Contestability for the construction of connection assets already occurs in the majority of cases, as TNSPs seek competitive tenders for this work. However, the benefits of that competition are generally either not passed onto, or are not apparent to, connection applicants (generators or other users), which appears to reflect a lack of transparency in the negotiating process.

6.2.3 Other measures considered

The Commission engaged Deloitte Touche Tohmatsu ("Deloitte") to provide advice on the feasibility of implementing contestability in the construction and/or the ownership of transmission connections in the NEM. Their report has been published alongside this report. A number of their recommendations feed into the Commission proposals above. In relation to facilitating a greater role for connection applicants in the process, Deloitte made the following additional recommendations:

- connection applicants should be given a role in the decision making on construction assets, by requiring that they must give final approval or rejection of the design and construction recommendations of the local TNSP; and
- parallel processing should be enabled, where the connection applicant wishes to speed up the connection process by taking on the risks involved in initiating some tasks with long lead times prior to the final Connection Agreement being signed.

We have concerns with Deloitte's recommendation that applicants must give final approval or rejection of the TNSP's recommendation on the selection of a contractor. We consider that this may create an unworkable decision-making process for the TNSP, whose board would still be ultimately responsible and liable for the decision taken. However, as described above, we consider that a TNSP should take into account the preferences and priorities of the connecting applicant.

The Commission agrees that there may be some benefit from enabling parallel processing. TNSPs do have an incentive to process connections in a timely manner, as they only start earning revenues for those assets once the connection has been completed. We understand that parallel process does happen now in some cases, but we consider applicants should have the power to require parallel processing, where they are prepared to take the associated risks. For example, some parties may prefer to underwrite the risks of the TNSP procuring long lead-time assets (e.g. delivery of large

184 First Interim Report, p. 171.

185 AGL, First Interim Report submission, p. 8; Private Generators Group, First Interim Report submission, p. 4; Infigen, First Interim Report submission, p. 5.

transformers can take up to 2 years) before their Connection Agreement has been finalised, in the knowledge that those costs would not be recoverable in the event that the Agreement was not finalised.

Box 6.3: Irish Single Electricity Market (SEM) arrangements

In investigating the issue of contestability, the AEMC has looked at the detailed framework for transmission connections that exists in the Single Electricity Market (SEM) combining Northern Ireland and the Republic of Ireland. The SEM contestability framework currently operates in EirGrid's territory in the Republic of Ireland. A greater degree of certainty appears to exist than in the NEM as to what elements are contestable, and how the contestability provisions work.

In the SEM, some contestability exists for ownership of connection assets as well as for construction. This is made feasible by the role of EirGrid, the Transmission System Operator (TSO). In the SEM, responsibility for transmission is split between two bodies: the TSO and the Transmission Asset Owner (TAO). The detailed design and construction of contestable assets is subject to TSO outline design and functional specifications. Design is submitted to the TSO for approval and there are unrestricted rights of TSO inspection during construction. The TSO can request spares, training and warranty periods. The TSO arranges for the provision of any contestable assets that the connection applicant does not elect to provide.

However, in its report to the Commission, Deloitte identified a number of barriers to the implementation in the NEM of the SEM connections framework:

- Differences between the SEM and the NEM, including that the SEM has one TNSP, as opposed to six, and an independent body (TSO) which has responsibility for many of the security and reliability standards that are with the TNSPs in the NEM. Recreating this approach in the NEM would require either the TSO to have detailed knowledge of all six TNSP networks, or harmonisation of standards etc.

- An independent TSO may face similar incentives in relation to security and reliability to those of TNSPs under current arrangements.

- There appears to be a limited market for provision of connection services - connection applicants generally have no interest in owning and operating assets. Benefits of a "build, own, operate" model may therefore be limited.

- Under Australian tax legislation, the transfer of assets to a TNSP would create a new tax liability for the TNSP.

Deloitte concludes that implementing a similar framework to the SEM would require substantial changes to the NEM regulatory framework and may not actually address the problems with the current connections framework.

Dispute resolution

The current rules set out the requirements and process to be followed to resolve transmission access disputes in relation to the terms and conditions of access for the provision of negotiated transmission services, including, for example, the appointment of a commercial arbitrator to resolve the dispute.[186]

There was not a clear consensus in submissions to the First Interim Report about the need for an enhanced dispute resolution process. Generators expressed a need to strengthen the process to enhance the negotiating power of connection applicants, while TNSPs and the AER were against any proposal for the AER to resolve disputes, due to a lack of relevant experience and concerns of a potential conflict with its monitoring and enforcement role.[187]

There were however, a number of suggestions as to why there have been no disputes referred to the AER for resolution by an appointed commercial arbitrator under the current rules. Of particular concern was the risk of a connection applicant jeopardising their relationship with the TNSP, by initiating a dispute resolution process, and the additional time it would add to the overall connection process.[188]

The Commission is not proposing any changes to the dispute resolution process. The issues raised in this area are not with the dispute resolution process itself, which has not to date been tested, but are symptomatic of the wider issues with connection applicants' position in negotiating connections. The proposals for enhancing the negotiating framework above should mean connecting parties have more information on which to base a decision about whether to invoke dispute resolution proceedings.

Prescribed connection services

In the First Interim Report we suggested that, if stakeholders were concerned about their ability to negotiate with monopoly TNSPs, it might be appropriate for connections to be regulated as prescribed services. In this way, the AER would determine an efficient level of costs, and TNSPs would have an incentive to further minimise costs. We suggested that, in particular, this could be of benefit to smaller (potentially renewable) generators with less experience of negotiating connection arrangements.

However, stakeholders responding to the report did not, in general, support this proposal. Concerns were expressed that it might add complexity, stifle innovation and

186 The dispute resolution provisions in the rules are in addition to any commercial arbitration terms that may appear in commercial contracts.

187 Private Generators Group, First Interim Report submission, p. 3; Grid Australia, First Interim Report submission, p. 43; AER, First Interim Report submission, p. 12.

188 AER, First Interim Report submission, p. 12; Victorian DPI, First Interim Report submission, p. 13; MEU, First Interim Report submission, p. 37; Clean Energy Council, First Interim Report submission, p. 13; Private Generators Group, First Interim Report submission, p. 8; Pacific Hydro, First Interim Report submission, p. 5; Infigen, First Interim Report submission, p. 8.

reduce flexibility.[189] While one renewable generator supported prescribing connection services, another suggested that recent increases in shared network costs indicated that prescribing connections may not ensure affordable and efficient outcomes.[190]

In light of these views, we have concluded that a more appropriate course of action is to focus on improving the negotiating framework through the proposals set out earlier. Treating connections as a prescribed service appears to be a disproportionate response although, as discussed in section 6.4, there may be additional reasons why this would add to the robustness of connection arrangements.

6.3 The provision of extensions

6.3.1 The issue

In order to connect to the shared transmission network, a connecting party (e.g. generator or large load) usually requires a new transmission line to be constructed from its facilities to the boundary of the assets used to provide the connection service (e.g. substation). We refer to this line as an extension. There is currently a high level of ambiguity in the NER relating to the treatment of extensions.[191]

It is not entirely clear in the rules whether extensions fall under the definition of a negotiated or non-regulated transmission service. This uncertainty stems in part from the limited guidance provided by the definition in Chapter 10 of the NER, where extensions are defined as being:

> "An augmentation that requires the connection of a power line or facility outside the present boundaries of the transmission or distribution network owned, controlled or operated by a Network Service Provider."

Moreover, the uncertainty is compounded by the degree of disconnect between the provisions in Chapter 5 that specify the connection process, and those in Chapter 6A that govern the economic regulation of services. Clause 5.3.6(k) of the NER states that:

> "Nothing in the Rules is to be read or construed as imposing an obligation on a Network Service Provider to effect an extension of a network unless that extension is required to effect or facilitate the connection of a Connection Applicant and the connection is the subject of a connection agreement."

However, there is no further discussion of extensions in Chapter 6A, either in relation to economic regulation or provision by TNSPs. Consequently, it is not clear whether

189 Victorian DPI, First Interim Report submission, p. 14; Grid Australia, First Interim Report submission, p. 44.

190 Infigen, First Interim Report submission, p. 9; Pacific Hydro, First Interim Report submission, p. 11.

191 Indeed it is not entirely clear whether the definition of an extension in the NER is consistent with the description above. Under our proposals in this section and section 6.4 below, it may become unnecessary to define extensions separately from other connection assets.

the rules require TNSPs to provide extensions and, if they do, what form of economic regulation (if any) they should be subject to.

The ambiguity in the rules has necessitated a degree of interpretation on the part of both TNSPs and connecting parties in establishing their respective obligations and rights with regard to extensions.

Grid Australia's interpretation

In order to provide some guidance on these matters (amongst others), Grid Australia has developed a Categorisation of Transmission Services Guideline, which sets out in practice how TNSPs approach extensions. In the Guideline, Grid Australia states that it considers that clause 5.3.6(k) of the NER cannot be interpreted as compelling TNSPs to build an extension, unless it has been agreed through a connection agreement.[192] Grid Australia also defines extensions as non-regulated transmission services, since it considers these works to be fully contestable.[193] Moreover, Grid Australia states in its submission to the First Interim Report that:[194]

> "Non-regulated services fall outside the boundaries of the existing network and are those services that are generally capable of being supplied in a practical and economic sense by TNSPs or third parties. More specifically, non-regulated services are provided by means of assets between the substation containing the transmission network connection point equipment and the generator or directly-connected load."

It therefore appears that in determining what type of transmission service extensions are, Grid Australia has considered whether or not the service is contestable. If the service is contestable, there is (in their view) no reason why TNSPs should be obligated to provide it. Further, because the provision of an extension is contestable, if a third party or the transmission user owned the extension it would not be economically regulated. Therefore, even if it is owned by the TNSP, it should be a non-regulated transmission service for consistency.

In Grid Australia's view these non-regulated assets sit outside a TNSP's "transmission system" and accordingly outside the NER – even if the TNSP itself owns the assets.[195] Grid Australia considers that to the extent that access to these assets is desired by other connecting parties this will occur through private, commercial negotiation.[196] We also understand that some TNSPs consider that while extensions sit outside the rules, they

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192 Grid Australia, *Categorisation of Transmission Services Guideline*, version 1.0, August 2010, p. 7.

193 Grid Australia, *Categorisation of Transmission Services Guideline*, version 1.0, August 2010, p. 7.

194 Grid Australia, First Interim Report submission, p. 39.

195 A transmission system is defined in Chapter 10 of the NER as a "transmission network, together with the connection assets associated with the transmission network, which is connected to another transmission or distribution system".

196 Additionally, that access to extensions could occur through Part IIIA of the Competition and Consumer Act 2010. This is discussed in further detail in section 6.3.2.

are covered by state legislation and regulations, and that this is sufficient in terms of regulation.

Other parties' interpretations

It is not clear that Grid Australia's interpretation of the rules is consistent with other parties' interpretation (or the original intention of the rules). For example, we understand that to the extent that the provision of extensions occurs in Victoria, they are treated as negotiated transmission services by AEMO. Additionally, some stakeholders, particularly generators, have raised concerns that there is currently ambiguity surrounding the definition of extensions, and associated obligations on TNSPs.[197]

We consider that there is considerable uncertainty in the rules regarding how extensions are to be regulated, and what TNSPs' and connecting parties' rights are in relation to these services. Our proposed policy to address this uncertainty is set out in detail below.

6.3.2 Commission proposals

The Commission proposes that, when looking to establish an extension between the connection assets and its facility the Commission proposes that the connecting party should have the choice of whether to:

- make use of any competition that exists in certain elements of the supply chain by issuing competitive tenders for those elements. In such circumstances, the TNSP could bid in the competitive tender; or
- benefit from a level of regulatory protection by requesting the TNSP to provide the end-to-end service of providing the extension as a negotiated transmission service.

We propose that the TNSP will be required to provide the end-to-end service, and to do so as a negotiated transmission service, where a connecting party requests it in the TNSP's local area.[198] In this case it would be bound by the transparency provisions of the negotiating framework, but not the proposed requirements to share tenders and business cases with the connecting party (as would be required for connections).

Where an extension is owned by the connecting party or a third party, it will be required to register as a TNSP or gain exemption from the AER from that requirement, as is currently the case. We propose that the conditions of such an exemption should include a requirement to allow third party access to the extension.

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197 LYMMCo, First Interim Report submission, p. 9; Pacific Hydro, First Interim Report submission, p. 11; Infigen, First Interim Report submission, p. 12; MEU, First Interim Report submission, p. 41.

198 Local area is defined in the NER as "the geographical area allocated to a Network Service Provider by the authority responsible for administering the jurisdictional electricity legislation in the relevant participating jurisdiction".

In some circumstances (set out later in this section) an extension might subsequently be required to become part of the shared network. In these circumstances, a non-TNSP owner would need to decide whether to:

- operate the assets as prescribed transmission services as a registered TNSP, with the revenue on the assets determined by the AER; or
- voluntarily sell off the assets at "fair value" to the incumbent TNSP, who would then roll the assets into its Regulatory Asset Base (RAB), and so its network.

This proposed framework could result in more generator-owned shared network assets. In order to alleviate concerns around the potential for discrimination in access to transmission networks, we propose that a provision should be inserted into the NEL to prohibit a single party from having controlling ownership of both a registered generator and registered TNSP.[199]

The following section explains the rationale for these proposals.

Workable competition in the service delivery chain for extensions

We consider that for the provision of extensions to be entirely unregulated (as Grid Australia contends), there must be workable competition for that provision. The presence of contestability – where legislative and regulatory barriers do not prevent the extension being provided by more than one party – is not sufficient in itself. We consider markets to be “workably competitive” where there is sufficient rivalry between firms to ensure that they strive to deliver the goods and services that their customers demand, at least cost. While firms may have a degree of market power, this will not be either substantial or sustainable and will be subject to competitive erosion over time. In other words, competition will drive the market towards efficient outcomes.

Where workable competition does not exist, some form of regulation is likely to be required. We therefore consider it important to assess whether the provision of extensions occurs within a market that is workably competitive.

The provision of extensions comprises a number of different "elements". In other words, there is a "service delivery chain" for extensions, which consists of all the major tasks necessary to provide an extension within the NEM. These are set out in Figure 6.1 below, along with the categories of market participant that currently provide these elements. The majority of extensions in the NEM are currently owned and operated by the incumbent TNSP. However, Grid Australia has submitted that there are 12 examples of extensions owned by parties other than TNSPs in the NEM.[200]

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199 This would not apply where an AER exemption was held, and so would primarily apply to ownership of shared transmission assets.

200 These were provided in Grid Australia’s submission to the First Interim Report. We are also aware of other examples not listed in this submission. For example, QGC Pty Limited has been granted "special authority" to own transmission lines in Queensland.

Figure 6.1 Current provision of the elements of an extension

	Element	Parties that provide the Element				Does the TNSP have an advantage?
		TNSP	Connecting Party	Contractors	DNSP	
1	Project Management e.g. management of site works, organising outage planning with local TSNP	advantage through economies of scope & experience	can undertake	can undertake	×	Yes
2	Obtaining Planning Permissions / Environmental Approvals	advantage through economies of scope & experience	can undertake	×	×	Yes
3	Obtaining Easements	advantage through legislative advantage e.g. can use existing easements	NSW third parties cannot gain easements; in Qld any licensed transmission entity can acquire land but requires Ministerial approval; and in Vic, SA, Tas all licensed electricity entitles can acquire land (although may be subject to Ministerial approval)	×	×	Yes
4	Detailed Design	can undertake	×	can undertake	×	No
5	Procurement of Materials / Resources	may experience economies of scope & experience	can undertake – may utilise the TNSP's ordering facilities (in order for the TNSP to ensure consistency of equipment)	can undertake	×	Yes
6	Construction	×	×	can undertake	×	No
7	Operation e.g. ensuring the asset is operated in accordance with jurisdictional requirements, insurance	advantage through economies of scope & experience	can undertake	×	×	Yes
8	Maintenance i.e. routine servicing of the plant or equipment ensuring it is kept in accordance with a specified set of standards	advantage through economies of scope & experience	×	×	advantage through economies of scope & experience	No
9	Ownership	can undertake	can undertake	×	×	No

Some of the elements in the provision of extensions can be, and are, undertaken by parties other than the TNSP or connecting party. For example, construction is generally undertaken by third party contractors – regardless of who is responsible for or owns the extension. Those activities that can be undertaken by a party other than the TNSP are coloured grey in the above table.

While competition is theoretically feasible for most elements of the service delivery chain, in a number of these individual elements the TNSP has a significant advantage in their provision in its local area. Generally TNSPs are protected by entry barriers and benefit from economies of scale, scope, experience and capability in providing these services. The services where the TNSP may experience these advantages are coloured red in the above table. A more detailed discussion of TNSPs' market power in the provision of these elements is contained in appendix B.

For example, in procurement the TNSP would have significant economies of scale, in that it would be purchasing a large volume of equipment such as switchgear for the shared network, as well as for extensions.[201] The TNSP therefore has an advantage over other parties that can provide this particular element.

Importantly, the above analysis indicates that in practice the TNSP is the only provider that can undertake all of the elements involved with the provision of extensions. That is, it can "bid" to provide connecting parties every element of the service delivery chain from project management through to ownership.[202] In contrast, other potential competitors involved in the delivery chain (e.g. independent contractors and DNSPs) can currently only undertake some of the services associated with providing an extension.[203]

Whilst in most jurisdictions a third party may be able to gain a transmission licence and provide an end-to-end service, this has not happened to date. Moreover, we do not consider that there are a sufficient number of extensions being constructed in the NEM that would enable a third party provider to gain sufficient scale providing end-to-end services. We understand that there are only a handful of extensions constructed throughout the NEM annually. Therefore, the services provided by the TNSP cannot be readily compared to the services provided by other parties. This ability to offer an end-to-end service may in itself place the TNSP in a more attractive position compared to other parties.[204]

This has a number of implications for the form of economic regulation, and access provisions, which are discussed in the sections below.

Form of economic regulation

Under the Commission's proposals, TNSPs can either bid in a competitive tender, or be required to provide an extension as a negotiated transmission service. This necessarily requires consideration of the form of economic regulation that will apply to TNSPs. Decisions about whether and how to impose regulation are generally made by reference to the level of competition, specifically:

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201 We understand that in some circumstances TNSPs may procure equipment on behalf of connecting parties in order to ensure consistency of equipment.

202 TNSPs contract out for the actual construction of the transmission assets. However, they still "bid" to provide a complete end-to-end service, with this component sub-contracted out.

203 There may be some circumstances in which a TNSP has less of an advantage in the provision of certain services, for example where HVDC above-ground transmission equipment is required.

204 We note that there may be some specific circumstances in which third parties can offer an end-to-end service on similar terms to a TNSP, e.g. a government agency may be able to provide infrastructure if it is deemed to be of state significance.

- regulation is usually limited to those instances where the existence of substantial market power results in prices that are materially higher than those that would be expected to eventuate if the market is workably competitive; and
- where regulation is imposed it seeks to bring about prices that provide a regulated business with the reasonable prospect of recovering its efficient costs, and to obtain a return on capital commensurate with the risks associated with its investment.

End-to-end service provision

The analysis above demonstrates that in most cases no party other than the incumbent TNSP can currently provide extensions as an end-to-end service. Therefore, we do not consider that the end-to-end provision of extensions occurs within a workably competitive market. The TNSP has advantages of economies of scale, scope, experience and capability in providing an end-to-end service. Connecting parties should therefore be protected through some form of regulation.

We consider that applying the provisions of the negotiating framework would provide some protection, and would also be straightforward to introduce. However, it would also be light-handed enough so as to not be unduly onerous on TNSPs. It would additionally allow for the possibility of future competition to develop in the market for an end-to-end service.[205]

Workably competitive elements

Where there is workable competition, we consider that the TNSP should compete on a level playing field with other participants, and so should not be required to provide any additional information than would be expected under a competitive tender.

A number of obligations are imposed on TNSPs relating to the information that must be provided when offering a negotiated transmission service. Moreover, as discussed in section 6.2.2 we are proposing to strengthen these information requirements. However, given that the aim of regulation is to mimic the outcomes of competitive markets, we propose to base these information requirements on what a connection applicant would normally require contractors to produce through a competitive tender process.[206] Therefore, we consider that it would be appropriate for the rules specifying the information that a TNSP must provide under a negotiated transmission service to also apply if a TNSP submits a bid under a competitive tender process.[207]

205 If this occurs, then the need for regulation could be revisited. However, as previously noted, we consider that the scale advantage of TNSPs is such that this is unlikely to eventuate.

206 We welcome feedback from generators and other parties in order to better understand the information that they require/receive in the connection process, and the competitive tendering of extensions.

207 Where a TNSP provides only a minor element of the extension supply chain (e.g. detailed design work), this would be unlikely to be classified as providing a transmission service.

Our proposals for improving the negotiating framework for *connections* consist of two sets of measures: enhancing the role of connecting parties in the connection process, and enhancing the transparency of the connection process. It is only the transparency provisions that we propose should apply to the provision of *extensions*.

We do not consider that it would be appropriate to require TNSPs to share tenders for construction of extensions with connection applicants. Unlike the construction of substations on the shared network, connecting parties would already have the option of running competitive tenders for the construction of extensions. Moreover, TNSPs may potentially be competing in these tenders with their own subcontractors. We therefore propose that this new obligation should only apply in relation to the construction of *connection* assets (excluding "extensions").

Table 6.1 below summarises the proposed requirements on TNSPs when providing extensions and connections.

Table 6.1 Summary of proposed requirements on TNSPs when providing connections and extensions

Connections	Extensions
• TNSP must publish: — standard contract terms, — design standards and philosophies for equivalent prescribed assets; • TNSP must provide to connection applicants: — Detailed cost, assumption and calculation information, including supporting evidence; • A power for AER to develop (and enforce) guidelines on specific information TNSPs should provide to connection applicants.	• TNSP must publish: — standard contract terms, — design standards and philosophies for equivalent prescribed assets; • TNSP must provide to connection applicants: — Detailed cost, assumption and calculation information, including supporting evidence; • A power for AER to develop (and enforce) guidelines on specific information TNSPs should provide to connection applicants.
TNSPs must: • provide to connection applicants all responses from contractors to the TNSP's tender for construction of connection assets, • provide to connection applicants detailed business cases for its decisions on choice of contractors, and • take account of the applicant's preferences in its choice of contractor	

As such, the information requirements placed on a TNSP when providing a negotiated transmission service would be no more onerous than those which a connection applicant would normally request contractors to provide under a competitive tender.

For completeness, we note that if parties other than the incumbent TNSP "bid" for some elements, then these would be unregulated from an economic regulation point of view.

In light of our proposals for different options for ownership (and consequent regulation) of extensions, it is important to clarify the arrangements for third party access to extensions. The following section explains our proposals for connecting to extensions as a means of gaining access to the transmission network.

Access to extensions

It is our understanding that users who request and finance extensions have generally had sole use of those extensions, with most generators and load locating close to the existing network. However, development of the network is changing. Generators may locate further away from the existing shared network e.g. wind-powered generators locating around favourable wind resources. Such connections are likely to require longer extensions and are consequently more likely to provide options for other users wishing to gain access to the transmission network. Therefore, it becomes an increasing possibility that third parties may wish to gain access to extensions going forward.[208]

We note that several submissions have contemplated that access to extensions could be gained through declaration of the line under Part IIIA of the Competition and Consumer Act 2010 (CCA).[209] We do not consider that this is a feasible prospect, given the criteria required to be considered by that legislation in order for access to occur (this is discussed more fully in appendix B).

Ownership by a TNSP

If the extension is owned by a TNSP, and a third party connects then we propose that the rules are clarified to specify that the line is upgraded (if required) in order to ensure that it can be operated to an unconstrained level. Upgrading the extension to be unconstrained ensures that the existing generator or customer is not disadvantaged by the TNSP providing access to the third party.[210]

Ownership by Third Parties

Clause 2.5.1(a) of the NER requires that only a licensed Network Service Provider (NSP) own, control or operate a transmission or a distribution system unless exempted

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208 For example, we note that this situation has already occurred in South Australia, where Prominent Hill mine has gained access to a transmission line owned by BHP Billiton.

209 TRUenergy, First Interim Report submission, p. 10; Grid Australia, First Interim Report submission, p. 42.

210 This is consistent with sentiments expressed by MEU and Hydro Tasmania in their submissions to the First Interim Report.

under clause 2.5.1(d).[211] Exemptions are granted by the AER in accordance with guidelines published by them.[212] The AER may also impose conditions on an exemption, including conditions relating to standards and regulatory controls in place for the network, access and charging. Therefore, if the connecting party or a third party owns an extension (i.e. transmission line) they should either be registered as a TNSP, or gain exemption from the AER from this requirement. The AER exemptions are discussed in further detail in appendix B.

We propose that generators owning transmission lines longer than 2km, and other parties owning transmission lines should gain exemptions from the AER to own and operate these assets.[213] We also propose that the AER guidelines are clarified in order to make a number of explicit provisions related to access clearer.

The conditions in the exemptions should include:

- requiring third party access to extensions to be explicitly contemplated, including that this should occur through a negotiate/arbitrate framework;
- requiring a more fully developed description of an appropriate dispute mechanism process, including a set of third party access principles that should be considered by an arbitrator;[214] and
- clarifying that if an extension (or any part of it) becomes part of the shared network then that extension (or the part of it) is no longer considered exempt.

This would ensure that there are arrangements in place setting out a process for both gaining third party access, and dealing with disputes that may arise in this context.

Transition to the shared network

Once a certain number of parties connect to an extension it may be more appropriate for the extension to be considered part of the shared network. Indeed, we are aware of at least one example in the NEM, where this reclassification has occurred. We therefore consider that the rules should be clarified as to when extensions should become part of the shared network, and considered to be providing “prescribed transmission services”. It is important to set out at what point this occurs in order to provide clarity and certainty of these issues to parties that own extensions.

We recommend that there should be two triggers for the extension (or part of it) being reclassified as part of the shared network:[215]

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211 This is also contained in the NEL: Part 2, Division 1, s11(2).

212 We note that exemptions can be gained from the requirement to register as a TNSP and/or the technical requirements as set out in Chapter 5 of the NER. We understand that all exemptions to date cover both of these components.

213 We explain the rationale for the 2km threshold in appendix B, but welcome stakeholder views on whether this is an appropriate length.

214 This is consistent with the principles contained in the Competition Principles Agreement, which include that a dispute mechanism is to be embodied in the access regime.

- where a DNSP wishes to connect to the extension; or
- where a TNSP is augmenting the existing shared network to facilitate additional capacity, and the most efficient option would be to utilise the extension.

This is consistent with the current definitions in the rules – a prescribed transmission service includes a connection service provided by a TNSP to connect to the network of another NSP.[216]

The incumbent TNSP would identify when these triggers were met, by undertaking a RIT-T to assess meeting a particular identified need. We propose that the rules should state that if a RIT-T finds that upgrading the network through utilising the extension is the most efficient option, the extension would become part of the shared network.[217] If a service is defined as part of the shared network, it would be provided as a prescribed transmission service and so funded by transmission users through Transmission Use of System (TUOS) charges. Necessarily, the assets associated with these services would be subject to a revenue determination by the AER.

If the extension was not owned by the TNSP, in these circumstances it would be up to the owner to decide whether:

- to operate the assets as prescribed transmission services as a registered TNSP, with the revenue on the assets determined by the AER – this could be considered a similar situation to Murraylink and Directlink; or
- to voluntarily sell off the assets at "fair value" to the incumbent TNSP, who would then roll the assets into its RAB, and so its network. We envisage that this would be the most likely scenario since it is unlikely that third party owners of extensions would want to be subject to requirements imposed on TNSPs in the rules.

While the connecting party may have an incentive to inflate the "fair value" price to the incumbent TNSP, this will be mitigated by the fact that the alternative is for it to be subject to an AER revenue determination.[218]

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215 If only part of an extension which is subject to AER exemption is reclassified as part of the shared network, then the exemption would still be required for the remainder of the extension.

216 Prescribed transmission services are defined in Chapter 10 of the Rules to include “connection services that are provided by a Transmission Network Service Provider to another Network Service Provider to connect their networks where neither of the Network Service Providers is a Market Network Service Provider.”

217 This should also be incorporated into the AER’s NSP Registration Exemption Guidelines, in order to make it clear that if one of the two triggers occurs, then the extension will transition to providing prescribed transmission services.

218 For example, schedule 6A.2.1 of the NER sets out how an opening regulatory asset base is to be established as the “prudent and efficient value of the assets that are used by the provider to provide those prescribed transmission services […] as determined by the AER”. Further, the AER must have regard to matters set out in clause S6A.2.2 of the Rules that relate to the prudency and efficiency of capital expenditure when setting this value.

Where a third party operates assets as providing prescribed transmission services, we propose that the third party should not be subject to the full set of obligations imposed on TNSPs under the rules. Registered TNSPs should therefore be treated as falling into one of two categories which, for the purposes of this report, we will refer to as "Class 1" and "Class 2" TNSPs.

Therefore, third party owned assets that become part of the shared network would be considered Class 2 TNSPs, in contrast to Class 1 TNSPs (i.e. the incumbent TNSPs in each jurisdiction). Class 2 TNSPs would undertake fewer functions than Class 1 TNSPs.[219] However, Class 2 TNSPs would still be required to provide a revenue proposal to the AER for assessment. Moreover, Class 2 TNSPs would still be obliged to provide a connection to their networks if required.[220]

Under this regime, Class 2 TNSPs would face significantly reduced obligations as compared to Class 1 TNSPs. The associated regulatory costs would still be material. However, we consider that the only realistic alternatives to this approach would be to:

- prevent all entry by third parties, and limit the provision of extensions to incumbent TNSPs (as in Great Britain); or
- develop a process to allow the forced transfer of extensions to the TNSP (as in the Republic of Ireland).

We prefer the proposal above to either of these approaches since we consider it to be less invasive on third parties' property rights. Private parties invest in facilities and infrastructure under an expected risk profile. Imposing forced transfer would potentially result in increasing the uncertainty about investment profiles for these businesses, which may discourage them from investment in extensions.

Generation and transmission cross-ownership

The inclusion of a mechanism that allows third-party owned extension assets to become part of the shared network is likely to result in increased diversity in parties owning elements of the shared network. This therefore has the potential to result in more generator-owned transmission assets than otherwise would have been the case.

If the third party owner is a generator then we consider there are significant competition concerns where there are shareholders who have an ownership stake in

219 For example, the Class 1 TNSP as the jurisdictional planning body would produce the Annual Planning Report, undertake SENE Design and Costing Studies upon request, and be required to provide extensions within its local area.

220 The process through which this would be facilitated largely exists within the NER already. The NER currently set out that a connecting party must first approach the local NSP (i.e. the incumbent or Class 1 TNSP) with a connection enquiry. If the local NSP considers that another party can more appropriately provide connection (e.g. the Class 2 TNSP) then it would direct the applicant to that other party (or, alternatively, consider the connection application jointly with the other party). If the connection enquiry was directed to this third party then they would be required to facilitate connection.

both the shared transmission network and generation assets. For example, there may be an incentive for the generator to operate its shared transmission network for its benefit, and at the detriment of other competing generators e.g. it may delay connection applicants to the network.

This matter has recently been contemplated by the MCE (now SCER) Standing Committee of Officials (SCO), which released a Consultation Regulation Impact Statement (C-RIS) on the possible anti-competitive behaviours associated with cross-ownership of transmission and generation within the NEM.[221] While the C-RIS does not represent the final views of SCER, it concluded that cross-ownership is not a problem currently in the NEM. However, the SCO did contemplate three options to deal with potential future cross-ownership concerns, namely:

- maintaining the current arrangements that rely on the existing provisions in the CCA and the NER to prevent competition concerns;
- enhancing current transmission ring-fencing guidelines; or
- inserting generation/transmission cross-ownership provisions in the NEL.

We consider that the first two proposed options will not provide the certainty required in order to mitigate the competition concerns. For example, the Australian Competition and Consumer Commission (ACCC) has previously commented that it does not consider that the current arrangements relying on the CCA are sufficient to deal with competition concerns in the electricity sector.[222]

We recommend that in order to guard against this possibility, a provision should be inserted into the NEL to prohibit a single party from being both a registered generator and a registered TNSP. In practice, this would only restrict generators from owning part of the shared network as any extensions not forming part of the shared network would be expected to be exempted from the requirement to register as a TNSP.

6.4 Clarifying the rules

6.4.1 The issue

In the First Interim Report we set out our view that many of the rules around connections (including extensions) are unclear and ambiguous. This results in considerable uncertainty as to how services that are required for a connection are regulated, and around the rights of TNSPs and connecting parties in relation to those services.

221 For example, through increasing the price of transmission, reducing quantity and quality of localised transmission, and reducing timeliness of transmission to competing generators. See: Ministerial Council on Energy Standing Committee of Officials, Consultation Regulation Impact Statement: Separation of generation and transmission, 11 August 2011.

222 ACCC, Submission to the Productivity Commission Review of National Competition Policy Arrangements, 13 July 2004.

The connections frameworks rely to a large extent on TNSPs and connecting parties (particularly generators) negotiating the terms of connections. However, it is difficult for parties to negotiate efficient outcomes if they do not know their underlying rights and obligations, and what rules apply to their negotiations.

We therefore suggested that, regardless of whether more significant policy changes are adopted, amendments should be made to clarify the interpretation and application of Chapters 5 and 6A, and the relevant definitions in Chapter 10, of the NER in relation to:[223]

- what each transmission service required to connect to the national grid involves, including the boundaries of the current categories of *shared transmission services*, *connection services* and services provided by means of *extensions*, and whether each service includes the construction of the underlying assets;
- how each such service is regulated under the Rules, including which services are *prescribed transmission services*, *negotiated transmission services* and *non-regulated transmission services*;
- what TNSPs' obligations are in relation to connections and the provision of each of these services.

Stakeholder views

The majority of stakeholders responding to the First Interim Report agreed with the issues we identified. The Government of South Australia supported the view "that the current NER provisions regarding connections lack clarity and would result in negotiations for new connections being more challenging than they should",[224] while the Victorian Department of Primary Industries suggested that this "ambiguity has led to a diversion in connection practices across jurisdictions".[225] A number of market participants agreed that the connections frameworks could usefully be clarified,[226] and Grid Australia suggested that "significant benefit can be gained by simplifying definitions and re-organising rules".[227]

Through a supplementary submission to the First Interim Report, Grid Australia further identified eight factors it considers contribute to confusion under the current frameworks:[228]

223 AEMC, *Transmission Frameworks Review*, First Interim Report, 17 November 2011, Sydney, p. 168.

224 Government of South Australia, First Interim Report submission, p. 4.

225 Victorian DPI, First Interim Report submission, p.13.

226 Alinta, First Interim Report submission, p. 21; International Power, First Interim Report submission, p. 46; Private Generators Group, First Interim Report submission, p. 3.

227 Grid Australia, First Interim Report submission, p. 10.

228 Grid Australia, Transmission Frameworks Review, Supplementary Submission on Connections in response to AEMC First Interim Report, July 2012, p. 5.

1. Key terms, concepts and their supporting definitions being expressed in an abstract way, rather than stating their functional and practical purpose, particularly those related to "services".

2. Excessive definitions, sub-definitions and cross referencing between them.

3. A lack of clarity around the relationship between "functional services" and the provision of "physical assets" needed to provide the functional services.

4. Multiple terms and definitions relating to the boundary of a transmission system.

5. The interface between Chapter 5 and Chapter 6A, the relationship between terms used for pricing purposes and terms used for connection and the provision of services and the interface with other Chapters of the Rules.

6. Terms in the Rules that are inconsistent with the same terms used in the National Electricity Law.

7. The use of multiple concepts and terms that overlap and conflict with each other.

8. The offer to connect process is too complex and prescriptive.

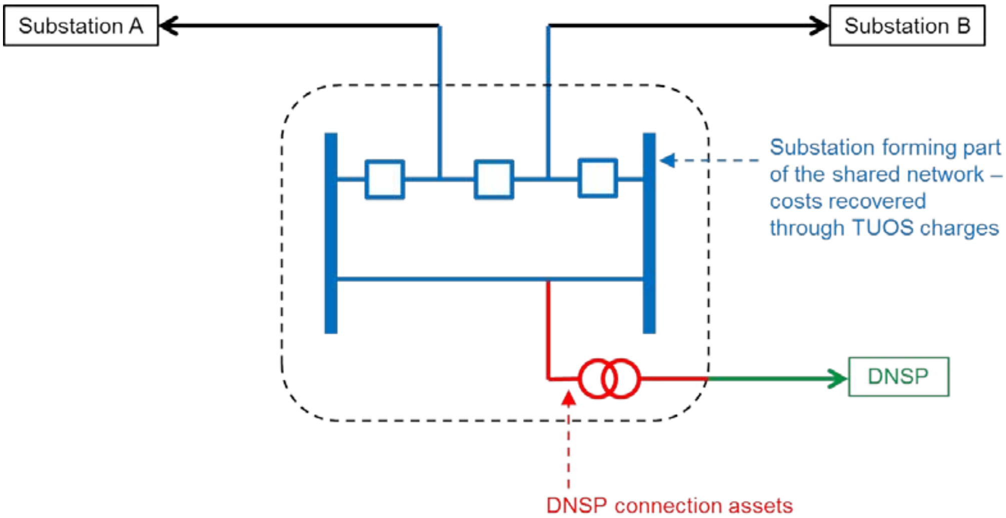
Further analysis

We agree with many of the issues presented by Grid Australia, but also consider that there are some more fundamental drivers for the confusion surrounding the connections frameworks.

The way in which the NER have evolved has led to assets required for connection being classified and charged for differently depending on the type of party that is connecting (i.e. a DNSP load, large directly connected load or a generator). The impacts of this can be demonstrated by use of the simplified connection diagrams that follow in this section.[229]

229 These diagrams are examples only, and it is acknowledged that these substation layouts may not be appropriate for all connections. However, the substation layouts are not critical and do not affect any of the categorisation issues discussed below.

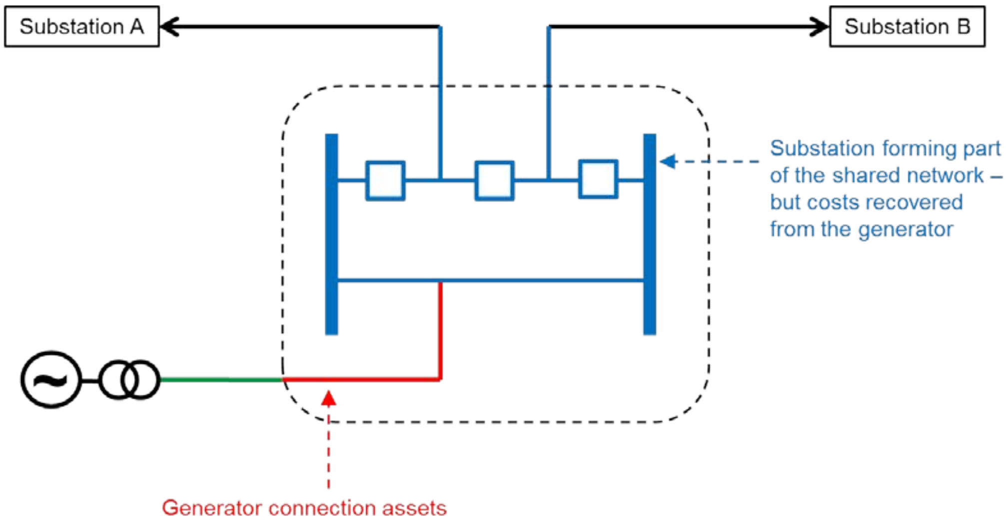
Figure 6.2 Simplified DNSP connection



In the case of the DNSP-only connection (Figure 6.2), in broad terms the substation (those assets coloured blue) would be providing a *prescribed Transmission Use of System (TUOS) service*, and its costs would be recovered from load through TUOS charges.[230] Under the current structure of TUOS charges, fifty per cent of the costs associated with the substation would be levied on a locational basis, with the other fifty per cent being "smeared" across all load users in the region.

The assets coloured red would be providing a *prescribed exit service*, and would therefore be classed as *connection assets*. The costs associated with these assets would all be recovered from the DNSP through a prescribed exit charge.

Figure 6.3 Simplified generator connection



230 The way in which TNSPs should attribute transmission system assets to categories of prescribed transmission services is defined in the AER's pricing methodology guidelines. See: AER, *Electricity transmission network service providers, Pricing methodology guidelines*, October 2007, section 2.4.

In the case of the generator-only connection (Figure 6.3), the frameworks are much less clear as to how the relevant assets should be treated. However, we understand that TNSPs generally take the same approach to classifying assets as set out above in relation to a DNSP connection.[231] That is to say that the assets in red are classed as *connection assets*. It is reasonably clear from the rules that *connection assets* provide *connection services*, and that *connection services* provided to a generator are classified as a *negotiated transmission service*.

However, the treatment of the assets coloured blue is much less clear. Since they are not *connection assets*, they must form part of the shared *transmission network*. However, unlike load, generators do not ordinarily pay charges for using the shared *transmission network*.

We understand that the practice of TNSPs, as set out in Grid Australia's Categorisation of Transmission Services Guideline, is to recover the cost of any works that are required to the shared *transmission network* in order to effect a generator connection on a "causer pays" principle. Therefore, such a *shared transmission service* would be funded by the generator as a *negotiated transmission service*.[232]

These arrangements lead to a number of issues, including:

- **Confusion and a lack of clarity.** For generators, the majority of charges required to effect a connection are charges for services other than *connection services*, which is far from intuitive.

- **Substations shared between generators.** We consider that, where a second generator connects to a substation, the level of service provided to first generator should be preserved.[233] Further, clause 6A.9.1(6) of the NER states that "the price for a *negotiated transmission system* should be subject to adjustment over time to the extent that the assets used to provide that service are subsequently used to provide services to another person". This is possible, and is appropriate, at a substation. However, to the extent that generators have funded augmentations deeper in the network it is not feasible to allocate costs in this way. This suggests that there is a need to define a boundary between the substation and the deeper shared *transmission network*.

- **Substations shared between generators and load.** Figure 6.4 below shows both a generator and a DNSP connected to the substation. It is not clear how this situation would be treated in practice. The frameworks suggest that the cost of the substation - the assets in blue - should be recovered from load through TUOS charges. Equally, TNSP practice suggests that these costs should be recovered from the generator as a *negotiated transmission service*. While some form of cost sharing would seem appropriate, it is far from clear how this would be achieved. The problem would also occur where a large load wanted to connect to a

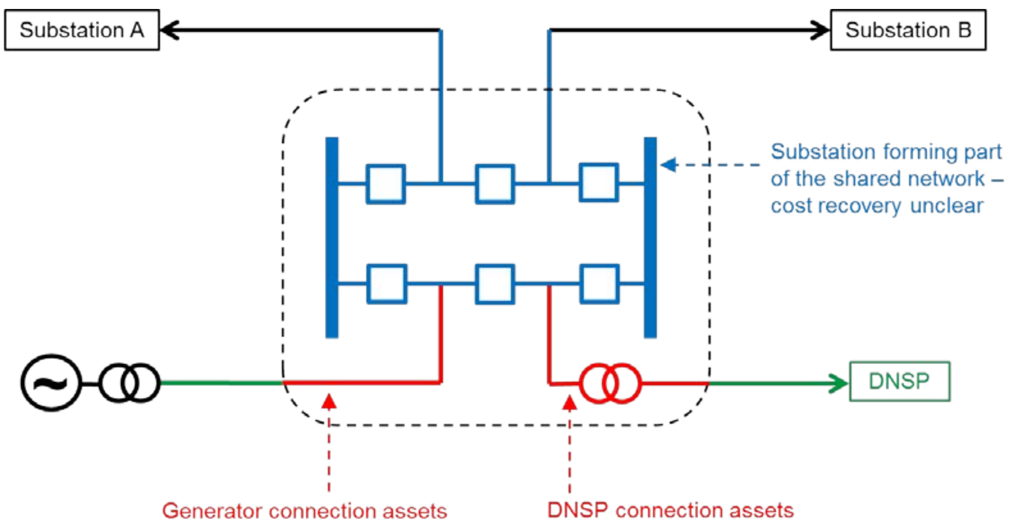
231 This approach appears to be reinforced by the transitional provisions in clause 11.6.11 of the NER.

232 Grid Australia, *Categorisation of Transmission Services Guideline*, Version 1.0, August 2010, p. 9.

233 This is consistent with our proposals for extensions, as set out in the previous section.

generator substation. For large load, although the *connection assets* are treated as providing a *negotiated transmission service*, the costs of the substation are recovered through TUOS charges.

Figure 6.4 Simplified DNSP and generator connection



Commission views

We continue to consider that the rules can, and should, be made significantly clearer. However, we note that there may be some limitations to this.

Individually, there are good reasons why it might be appropriate to treat services provided to load and generation differently - for example, negotiation between two regulated monopolies raises potential concerns over whether the outcomes would provide value for consumers, but more efficient outcomes may be achieved through lighter-handed regulation where those concerns do not arise. However, the differing treatment is one of the main reasons for the current lack of clarity in the rules, and poses a major obstacle to simplifying the rules.

Box 6.4 describes the connection arrangements that apply in New Zealand. While these are simple and robust, to replicate them in the NEM would imply treating substations as providing *prescribed transmission services* for both load and generation. Given that, to date this differing treatment has not to our knowledge caused any material issues for TNSPs or users in how assets are provided or funded, we do not currently consider that the issue warrants such a major policy change. However, it is not clear what would happen in the circumstance where a new large load wanted to connect to an existing generator substation, or vice versa. This appears to present a conflict which the rules do not contemplate or resolve. If this situation arises, this issue would need to be addressed, but might have to be left to the TNSP's discretion.

Box 6.4: Connection charging in New Zealand

In New Zealand, similarly to the NEM, only load users pay charges for the use of the shared network. The Transmission Pricing Methodology (TPM) contains rules that can be used to define any asset as being either a Connection Asset or an Interconnection Asset. Transpower, the TNSP, is funded to provide Interconnection Assets through Interconnection Charges levied on load users. This can be thought of as being equivalent to TUOS charges in the NEM, although the Interconnection Charge is recovered entirely on a non-locational basis.

The costs of Connection Assets are recovered through Connection Charges levied on connecting parties. The definition of Connection Assets would include all the substation assets coloured blue in Figures 6.2-6.4. If only the DNSP was connected, it would pay for 100 per cent of the assets coloured red and those coloured blue. Similarly, if only the generator was connected (as in Figure 6.3), it would pay for 100 per cent of the red assets and the blue assets.

The TPM also contains rules for allocating the costs of Connection Assets between different connecting parties. This is done on the basis of Anytime Maximum Demand (AMD) and Anytime Maximum Injection (AMI). Therefore, if both the generator and DNSP were connected (as in Figure 6.4), each would pay for 100 per cent of the sole-use Connection Assets (those coloured red). The costs of the substation (the assets in blue) would be shared between the two parties. If, for instance, the generator's AMI was 600MW and the DNSP's AMD was 400MW, the generator would pay sixty per cent of these shared costs and the DNSP would pay forty per cent.

We do consider, however, that it might be possible and desirable to recategorise all substations as providing *connection services*. This would go a long way to simplifying the frameworks, resulting in generators only having to pay charges associated with connection assets. It would also allow for the substation to be differentiated from the deeper shared *transmission network*. Finally, it might also increase cost reflectivity, as for load, the costs of substations would be recovered completely from the connecting party, rather partly smeared over all load users within a region. We would be interested in stakeholder views on this matter.

Our proposals below attempt to simplify and clarify the rules as much as possible without changing the fundamental classification of assets for the different connecting parties. We consider this simplification could go a lot further if the treatment of substations was consistent across the different users.

6.4.2 Commission proposals

The Commission has considered how best to achieve the desired clarity in the rules for connections, and believes that meaningful clarification is likely to involve significant redrafting of sections of Chapters 5, 6A and 10. We have not attempted to undertake the task of rule redrafting at this stage, but have worked with law firm Baker & McKenzie to set out a number of principles, which the Commission proposes should be reflected in a redrafted set of rules. The principles are set out below. The key principles include:

- fundamentally, all services provided by a TNSP can be termed transmission services; distinctions are only required to accommodate different charging arrangements;
- the *transmission network connection point* should be clearly defined as the point at which a generator physically connects its equipment/assets to the relevant *transmission system* (and should be named the transmission system connection point); and
- reflecting the policy proposals in section 6.3 above, all *transmission system* assets should be subject to the NER.

Where a distinction is necessary, the proposed changes reflect the policy changes proposed for consultation in this chapter, rather than current policy and/or practice. Clearly we will have to ensure that the final policy positions we take on all the connections issues are reflected in the rules; as such some of the principles proposed here may be subject to change to reflect policy decisions.

Other than where they reflect the proposed policies outlined in this chapter, the Commission's principles below are largely consistent with the approach set out by Grid Australia in their supplementary submission on connections. We welcome stakeholders' views on both sets of proposals.

Principles for connection rules

The main principles are listed below, categorised into boundary issues, service descriptions and charging. Italicised terms used in this section have the meaning (if any) given to those terms in the NER.

Boundary issues

1. A *Generator's connection point* should be clearly defined as the point at which the relevant *generating plant* is physically connected to the relevant *transmission system* (a *transmission system* is a *transmission network*, together with the *connection assets* associated with that *transmission network*).

2. The definition of *transmission network connection point* should be replaced with a definition of transmission system connection point (TSCP).[234] A *Generator* connects its *generating plant* to *connection assets*, which are owned by the TNSP and part of the TNSP's *transmission system*. *Generating plant* does not connect directly to the *transmission network*.

234 Note: this logic could also be extended to other definitions in the NEM Rules, e.g. with "*Transmission Network Service Provider*" becoming "Transmission System Service Provider".

3. The distinctions between *connection assets* and *transmission network* assets should be limited to:

   (a) who the TNSP should charge for the construction, operation and maintenance of those assets; and

   (b) the services that a *Generator* can expect from specific assets. While a *Generator* should be entitled to some level of service from *connection assets*, it does not have any entitlement to a specific level of service from *transmission network* assets.

4. *Connection assets* should be defined as *transmission system* assets used solely to facilitate a user's access to the *transmission network*. For *Generators*, *connection assets* should also specifically include *transmission system* assets (such as *substations*) used by multiple participants, but "caused" by the *generating plant's* connection to the *transmission system.*

5. *Transmission network* assets should be defined as all *transmission system* assets other than *connection assets*.

6. We do not see any compelling reason to separately identify *extensions* in the rules. An *extension* should be treated consistently with any other *connection asset* or *transmission network* asset (as the case may be).[235] The distinction in the requirements on TNSPs when providing the assets can be set out in the *negotiating framework*.[236]

7. All *transmission system* assets should be subject to the NER (including in the case of *connection assets*, the relevant TNSP's negotiating framework). Consideration should be given to whether the concept of *non-regulated transmission services* is required in the NER.

Service descriptions

1. The existing multiple categories of "services" provided to users should be rationalised and structured more clearly.

2. The linkages between the charges paid by a user and the services provided to that user should be maintained. As *Generators* do not pay any charges for use of the *transmission network*, the rules should not recognise any services provided to *Generators* in respect of the transmission network (other than development of *augmentations* to the *transmission network*, which would be provided as part of a *connection service*). This conclusion will need to be revisited if the rules are subsequently amended to provide that *Generators* are entitled to firm access rights or other services in respect of the *transmission network* (for example, if the

235 Where an extension is provided by the connecting party rather than the incumbent TNSP, this would generally be subject to an AER exemption and therefore not provided under the rules.

236 This will also allow greater flexibility to change those requirements if the level of competition in the provision of the assets changes over time.

optional firm access model proposed by the Commission in chapter 3 of this report was to be adopted).

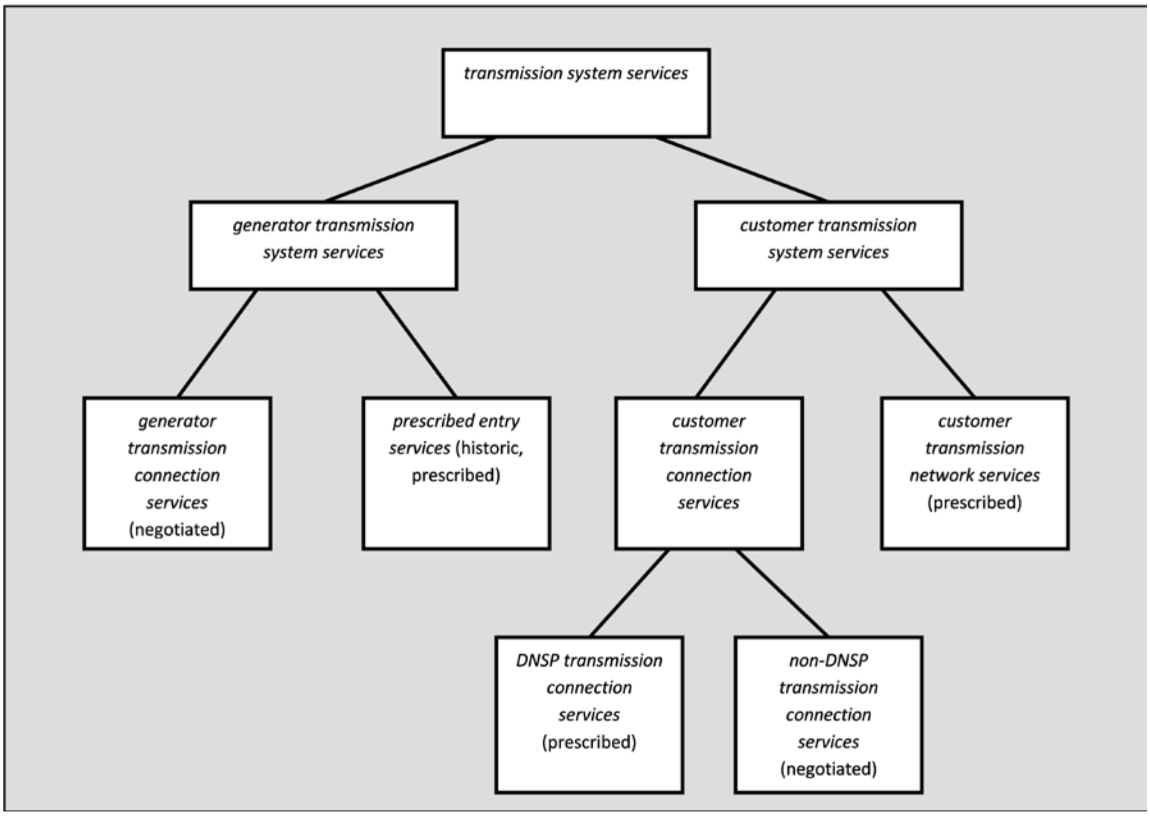
3. *Generator connection services* should therefore be defined as:

   (a) the development/construction of *connection assets* and any *augmentations* to the *transmission network* required by the *Generator*[237] and the ongoing operating and maintenance of those *connection assets*; and

   (b) the provision of *power transfer capability*[238] through the *connection assets* to allow the *Generator* to inject electricity generated by its *generating plant* into the *transmission network*.[239]

4. All *Generator connection services* provided by a TNSP should be subject to the *negotiating framework* approved by the AER for that TNSP.

Figure 6.5 Proposed definition of services



237 It should be noted that these services are, in respect of augmentations to the transmission network, limited to the development/construction of the relevant augmentation. Once the augmentation has been developed/constructed, the Generator does not receive any additional service in respect of the augmentation assets or have any specific rights in respect of the augmentation assets.

238 This definition has been used to describe the transfer of power from a Generator's TSCP to the relevant transmission network (i.e. through the connection assets). The current definition of power transfer capability does not adequately accommodate this concept and would need to be amended as it refers only to power transfer though a transmission network.

239 These services will need to recognise the possibility of other users subsequently connecting to and using the relevant connection assets.

Figure 6.5 above represents the proposed services definitions incorporated into the NER which are relevant to the provision of transmission services.

Charging

1. Generator transmission connection charges should apply for Generator transmission connection services. Generator transmission connection charges are "negotiated" charges.

2. Generator transmission connection charges should recover all of the TNSP's costs of:

   (a) developing / constructing any *connection assets* (defined above as all *transmission system* assets "caused" by the *generating plant's* connection to the *transmission system*) and the ongoing operating and maintenance of those *connection assets*; and

   (b) any other *transmission system* assets provided as part of the *connection service* by the relevant *generating plant* (e.g. *augmentations* to the *transmission network* requested by the *Generator*).

3. If other users subsequently connect to and use *connection assets*, those users should bear a reasonable share of the costs of developing / constructing those *connection assets* and the ongoing operating and maintenance of those *connection assets* (including reimbursement of the *Generator* to the extent that those costs have been funded "up front").

4. A TNSP's *negotiating framework* should specifically set out the basis on which a *Generator* will be reimbursed for other users connecting to its *connection assets*.

5. We do not see any compelling reason to separately identify *funded augmentations* in the NER. The concept of *funded augmentations* should be rolled together with *augmentations* funded under Rule 5.4A(f), as set out in point 2 (b) above.

The asset description, service description and charging arrangements in the NER are all inextricably linked. Although the clarifications proposed above are not intended to materially depart from the existing commercial arrangements required by the rules, they will require a reasonable number of amendments to the rules. These amendments will include:

- accommodating amended definitions of *connection assets* and *transmission network* assets to clarify the boundary between the classes of assets (for both *Generators* and *loads*);

- ensuring the NER reflect consistently that users connect to the *transmission system*, not *transmission networks*, and that TNSPs own and operate *transmission systems* rather than just *transmission networks*;

- rationalise the use and structure of service descriptions / definitions to reflect the definitions of *connection assets* and *transmission network* assets;

- rationalise the use and structure of charges descriptions / definitions to reflect the rationalised service descriptions;
- remove unnecessary concepts such as, potentially, *extensions* and *funded augmentations*; and
- clarifying the content requirements of TNSP *negotiating frameworks*.

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
CCA	Competition and Consumer Act 2010
COAG	Council of Australian Governments
C-RIS	Consultation Regulation Impact Statement
DNSP	Distribution Network Service Provider
DPI	Victorian Department of Primary Industries
DSP	Demand-side Participation
IRSR	Inter-Regional Settlements Residue
LRIC	Long Run Incremental Cost
LRMC	Long Run Marginal Cost
LRPP	Last Resort Planning Power
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NEO	National Electricity Objective
NER	National Electricity Rules
NFA	Non-firm Access
NPV	Net Present Value

NSP	Network Service Provider
NTNDP	National Transmission Network Development Plan
OFA	Optional Firm Access
RAB	Regulatory Asset Base
RIT-T	Regulatory Investment Test for Transmission
RRN	Regional Reference Node
SCER	Standing Council on Energy and Resources
SCO	Standing Committee of Officials
SEM	Single Electricity Market
SRA	Settlements Residue Auction
TAO	Transmission Asset Owner
TNSP	Transmission Network Service Provider
TSO	Transmission System Operator
TUOS	Transmission Use of System

A Alternative access models

In the First Interim Report the Commission presented for stakeholder comment five alternative packages for providing generators with access to the transmission network:

1. an open access regime;

2. open access with congestion pricing;

3. generator reliability standards;

4. regional optional firm access; and

5. national locational marginal pricing.

Of these, the Commission has decided to progress package 1, which is closest to the status quo, and package 4, which introduces an optional firm financial access product for generators (although the settlement mechanism for this draws from package 2).

This appendix sets out why the Commission has decided not to progress the remaining three packages. The appendix also discusses other access models proposed by stakeholders in response to the First Interim Report and provides a comparison of those models with the optional firm access (OFA) model described in chapter 3.

A.1 Open access with congestion pricing

The purpose of this model was to introduce a market-wide mechanism to better maintain incentives for generators to bid in a cost-reflective manner when the network is constrained.[240] This mechanism, termed the shared access congestion pricing (SACP) mechanism, would effectively put a value or price on congestion so that generators would take account of it in constructing their offers. Access to the transmission network would continue to be based on generator bids and network availability, as occurs in practice under the status quo.

A.1.1 Stakeholder views

A number of stakeholders expressed support for the introduction of a congestion pricing mechanism. These stakeholders considered that the model would:

- encourage more cost reflective bidding and so improve dispatch efficiency;[241]

- provide additional information on congestion costs;[242]

240 For a full discussion of this model refer to chapter 7 of the First Interim Report.

241 Alinta, First Interim Report submission, p. 9; International Power, First Interim Report submission, p. 19; Government of South Australia, First Interim Report submission, p. 1; Victorian DPI, First Interim Report submission, p. 4.

- be fairly simple to implement;[243] and
- may improve the safety, security and reliability of the network.[244]

Those that supported this package generally supported its implementation in combination with further change.[245] This was because the model was not seen to improve investment signals for generators and so would not resolve longer term investment coordination issues. For example, International Power noted that although it "favours the SACP initiative, this on its own will not achieve the majority of the stated desirable outcomes".[246]

The Energy Users Association of Australia (EUAA) supported the intent of the mechanism to reduce disorderly bidding, but considered that generators should not be allocated the hedging element of the mechanism - the constraint support contract (CSC) - on the basis that generators do not pay transmission use of system charges.[247]

Infigen, while favouring the status quo, considered more work was warranted to be better understand this option.[248]

In contrast, other stakeholders were concerned that introducing a congestion pricing mechanism:

- could reduce liquidity of the contract market;[249]
- would not resolve locational signals[250] and could even reduce locational signals;[251] and
- may create additional problems or could be unfair to existing generators.[252]

Stakeholders that did not necessarily support the model noted that further analysis would be required to demonstrate that the benefits would outweigh the costs of implementation.[253]

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242 AER, First Interim Report submission, p. 4.

243 Alinta, First Interim Report submission, p. 9.

244 International Power, First Interim Report submission, p. 19.

245 Alinta, First Interim Report submission, p. 9; International Power, First Interim Report submission, p. 9; Government of South Australia, First Interim Report submission, p. 1; Victorian DPI, First Interim Report submission, p. 4.

246 International Power, First Interim Report submission, p. 19.

247 EUAA, First Interim Report submission, pp. 4-5.

248 Infigen, First Interim Report submission, p. 2.

249 NGF (Frontier report), First Interim Report submission, p. 9; Origin Energy, First Interim Report submission, p. 11.

250 Origin Energy, First Interim Report submission, p. 11.

251 MEU, First Interim Report submission, p. 16; NGF (Frontier report), First Interim Report submission, p. 10.

252 NGF (Frontier report), First Interim Report submission, p. 10; ERM Power, First Interim Report submission, p. 2.

A.1.2 Commission's conclusions

While the package is intended to resolve disorderly bidding, it does not address the network congestion which underlies the problem, nor does it provide any long-term locational signals for new investment in generation.

The OFA model also operates as a congestion management regime, similar to package 2, with network access - in the absence of any firm generators - allocated on the basis of availability rather than dispatch. However, it is designed to provide a far greater range of potential benefits. It provides locational signals for generators - in the form of firm access charges - which signal the long-term costs of transmission, and would encourage market-led development of the transmission network.

The Commission does not believe that it would be appropriate to implement package 2 alone. If the decision is made to undertake substantive changes to transmission arrangements, then those reforms should aim to address all of the objectives of this review, which include providing arrangements for transmission and generation investment that minimise expected total system costs. However, the SACP mechanism provides an appropriate basis for addressing productive efficiency issues associated with disorderly bidding. For this reason, it has been incorporated within the OFA model.

A.2 Generator reliability standards

The purpose of this model was to introduce a transmission reliability standard for generators, which would increase certainty for generators by defining a level of access to the transmission network that TNSPs would be mandated to provide.[254] Generators would face a transmission use of system charge to reflect the costs to TNSPs of maintaining the generator reliability standard.

A.2.1 Stakeholder views

The majority of stakeholders did not support the introduction of generator reliability standards. These stakeholders considered that the model would:

- lack flexibility, and so be of limited use to generators;[255]
- inappropriately structure locational signals for investment in generation;[256]
- fail to provide arrangements for efficient investment in transmission;[257] and

253 Grid Australia, First Interim Report submission, p. 17; NGF (Frontier report), First Interim Report submission, p. 2; Origin Energy, First Interim Report submission, p. 11.

254 For a full discussion of this model refer to chapter 8 of the First Interim Report.

255 Grid Australia, First Interim Report submission, p. 18; Government of South Australia, First Interim Report submission, p. 1; International Power, First Interim Report submission, p. 19.

256 Grid Australia, First Interim Report submission, p. 18; Alinta, First Interim Report submission, p. 10; MEU, First Interim Report submission, p. 18.

- fail to resolve short-run congestion and disorderly bidding.[258]

ActewAGL supported generator reliability standards, on the basis that it would improve the efficiency of transmission pricing, but held some concerns with the model.[259]

The AER supported further consideration of this package, but preferred a combination of the second and fourth reform packages.[260]

A.2.2 Commission's conclusions

The Commission has concluded that consideration of package 3 should not be progressed further. The generator reliability standards model lacks flexibility in that it mandates firm access for all generators. In contrast, the OFA model allows generators to select the option that most closely meets their requirements. This should better allow for co-optimised outcomes between generation and transmission, promoting overall efficiency in the market.

The Commission was also concerned that mandating firm access might lead to generators "queuing": being unable to connect to the network for a number of years while waiting for deeper network reinforcements to be completed. Such an outcome - which has been observed in other markets with mandatory firm access - might negatively impact on competition in the wholesale market. Under the OFA model, even if firm access is not available for a period of time, generators are still able to connect on a non-firm basis and participate in the market.

A.3 National locational marginal pricing

The purpose of this model was to promote a deeper and more liquid market in energy trading by providing generators with compensation for being constrained off or on and a hedge against (market-wide) basis risk.[261] Under this model, fully firm financial transmission rights to a single national hub would be auctioned. Generators that purchased firm access rights would be settled at a single "system marginal price". Load would also be settled at this single price. Non-firm generators - those that did not purchase rights - would be settled at their local marginal price (LMP).

An uplift charge would be levied on consumers to ensure that the residues available through settlement were equal to the compensation payments necessary to provide fully firm access.

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257 Victorian DPI, First Interim Report submission, p. 5; EUAA, First Interim Report submission, p. 5; Clean Energy Council, First Interim Report submission, p. 9; Pacific Hydro, First Interim Report submission, p. 7; Origin Energy, First Interim Report submission, pp. 12-13.

258 Alinta, First Interim Report submission, p. 10; NGF (Frontier report), First Interim Report submission, p. 11.

259 ActewAGL, First Interim Report submission, p. 4.

260 AER, First Interim Report submission, p. 4.

261 For a full discussion of this model refer to chapter 10 of the First Interim Report.

The model would introduce a single NEM-wide TNSP and a single set of planning standards for generation and load. This set of standards would determine when new transmission investment was required to accommodate the release of incremental long term firm access rights. The TNSP would be exposed to a portion of the uplift charge to incentivise it to ensure that sufficient network capacity was made available on an operational basis.

A.3.1 Stakeholder views

There was little support for this model overall.

The National Generators Forum (NGF) considered that the model had some theoretical appeal. For example, the NGF noted it represented a coherent market design as it appropriately recognised the trade-off between firm access and cost.[262]

However, the majority of those stakeholders that commented considered that the complexities of the model, including those associated with introducing a single NEM-wide TNSP, would be difficult to resolve, and so the model:

- would be unlikely to represent a proportional response to the issues identified;[263] and
- could not be implemented in a timely fashion.[264]

Stakeholders were also concerned that the model would:

- create inefficiency by introducing a single national price for load;[265]
- increase customer risk through the uplift and balancing charges;[266]
- introduce additional basis risk;[267] and
- create a barrier to new entrants.[268]

262 NGF, First Interim Report submission, p. 21.

263 Alinta, First Interim Report submission, p. 11; EUAA, First Interim Report submission, p. 6; Origin Energy, First Interim Report submission, p. 14; MEU, First Interim Report submission, p. 21; Grid Australia, First Interim Report submission, p. 21.

264 AGL, First Interim Report submission, p. 7; LYMMCo, First Interim Report submission, p. 7.

265 NGF, First Interim Report submission, pp. 22-23.

266 MEU, First Interim Report submission, p. 21; NGF (Frontier), First Interim Report submission, pp. 28-29.

267 International Power, First Interim Report submission, p. 22; Pacific Hydro, First Interim Report submission, pp. 8-9; NGF (Frontier), First Interim Report submission, p. 27.

268 ERM Power, First Interim Report submission, p. 2.

A.3.2 Commission's conclusions

The Commission has decided that it would not be appropriate to consider this model further. In particular, the Commission considers that attempting to create a single TNSP at this stage of the market's evolution is likely to represent a disproportionate response. Combined with efficiency concerns regarding the pricing of load on a national basis, the Commission has concluded that it would be appropriate to retain a regional approach (but to take steps to promote nationally coordinated transmission planning).

The Commission also does not consider it appropriate to expose consumers to the uplift charge required to ensure that access rights are fully firm. Instead, we consider that the exposure of TNSPs to a portion of these costs would, by itself, be likely to have a significant effect on the ultimate firmness of the access rights.

A.4 Comparison of stakeholder models

In response to the First Interim Report, a number of stakeholders submitted their own access models. In many cases these were similar to the package 4 regional firm access model, but they aimed to address perceived limitations with that model. These models are described below.

Stakeholders were concerned that the regional optional firm access model would:

- fail to resolve disorderly bidding;[269]
- fail to provide greater generator certainty, noting: that without a deep connection charge, generators' ability to access the network may be eroded;[270] that compensation would be scaled back during times of congestion that resulted from outages;[271] and that there would be limited incentives for TNSPs to provide the access that generators require;[272] and
- fail to achieve either of the above objectives, as a consequence of trying to achieve both simultaneously.[273]

The Commission thanks those stakeholders who submitted alternative models. The OFA model described in chapter 3 of this report has adopted a number of suggestions proposed as part of the stakeholder models. The Commission believes that these changes contribute to a significant improvement in the model from that which was

269 International Power, First Interim Report submission, p. 20; Alinta, First Interim Report submission, p. 10; AER, First Interim Report submission, pp. 4-5.

270 International Power, First Interim Report submission, pp. 23-25; Alinta, First Interim Report submission, pp. 11-13.

271 Origin Energy, First Interim Report submission, pp. 13-14.

272 Alinta, First Interim Report submission, p. 11.

273 International Power, First Interim Report submission, p. 21; AGL, First Interim Report submission, pp. 6-7; LYMMCo, First Interim Report submission, p. 7.

presented in the First Interim Report. Four measures in particular, reduce the incentives for disorderly bidding and increase generator certainty:

- access (entitlements) for firm generators would be allocated on the basis of availability, rather than by a comparison to their hypothetical level of dispatch in an unconstrained merit order;
- access (entitlements) for non-firm generators would be allocated on the basis of availability, rather than their actual level of dispatch, basing settlement on the SACP mechanism;
- generators could procure an amount of firm access higher than their power station capacity, in order to increase their effective access level when transmission conditions mean that firm access is scaled back; and
- generators could procure firm inter-regional rights which, in combination with the firm access standard, would preserve a level of interconnector capacity.

A.4.1 International Power

The following table compares the International Power access model with the OFA model as it is described in chapter 3 of this report. As can be seen, they are aligned in many ways.

The areas of inconsistency, and reasons for the different approach taken by the AEMC in the OFA model, are discussed below.

Table A.1 Comparison of International Power and OFA access models

Model element	Consistency	International Power approach	OFA approach
Optional firm access right	Consistent	Generators choose the level of access they wish to purchase, so can be partially firm.	Same as International Power.
Access standard	Consistent	TNSPs must plan the network to accommodate aggregate firm access rights.	Same as International Power.
Access charge	Consistent	Generators pay TNSPs for the cost of providing firm access.	Same as International Power.
Dispatch	Consistent	No change to current dispatch process.	Same as International Power.
Tradeability of access rights	Consistent	Access rights should be tradeable.	Same as International Power.
Maximum level of firm access	Consistent	Unlimited, although effective access level is limited to power station capacity.	Generators can procure an unlimited amount of firm access, but will only receive entitlements based on their offered availability, which therefore limits their effective access level to power station capacity.
Interconnector planning	Partially consistent	New planning standards should ensure level of firmness for interconnectors.	New planning standards would recognise firm inter-regional rights, delivering the same objective of a higher degree of interconnector firmness, but in a different way to that proposed by International Power.
Transition	Partially consistent	Generators with existing "agreed access" have this preserved at no extra cost.	Existing generators are allocated transitional access at no cost, but this is sculpted back over time.
Access term	Partially consistent	Access would be long-term (perhaps indefinite).	Access term would be chosen by generators.

Model element	Consistency	International Power approach	OFA approach
Access pricing	Partially consistent	A one-off access charge, based on a deep connection charges, would be payable at access start.	Access charges would be based on a long run incremental pricing methodology, which differs from a deep connection charge. The default payment profile would be an annual charge.
Loss factor rebate	Not inconsistent	Generators should be rebated difference between average and marginal losses.	Marginal loss factors should be used for dispatch to ensure productive efficiency, which generally creates a settlements residue. If generators fund transmission, through firm access charges, then there may be merit in returning such settlements residue to them. How this would be accommodated within the OFA model has not been developed.
Limitations on non-firm generator offers	Inconsistent	Non-firm generators may not offer when relevant constraints bind.	No limitations on non-firm generator offers.
Settlement between non-firm and firm generators	Inconsistent	Done by TNSP (but only when non-firm generators breach offer restrictions).	Done by AEMO as part of market settlements.
Basis for settlement	Inconsistent	Based on gross incremental revenue (i.e. regional reference price).	Based on net incremental revenue (i.e. flowgate prices, equal to regional reference price minus local marginal price).

Access pricing

For the ways in which the LRIC access pricing methodology differs from a deep connection charge, and reasons why it has been preferred in the OFA model, please see section 6.3.1 of the staff Technical Report.

Limitation on offers of non-firm generators

The International Power model proposes that non-firm generators must withdraw their dispatch offers (and partially-firm generators correspondingly reduce their offered availability to their firm access level) whenever a "relevant" constraint binds: meaning a constraint in which the output of the generator appears as a term on the left-hand-side of the constraint. The AEMC package has no corresponding requirement.

There are two concerns with this proposal: theoretical and practical.

At a theoretical level, there should be no objection to non-firm generators being dispatched through a binding constraint and causing a firm generator to be constrained off, so long as: firstly, the non-firm generator values use of that scarce transmission capacity more than the firm generator; and secondly, the firm generator is compensated so that it is indifferent as to whether it is dispatched or constrained off. Conversely, the limitation in the International Power model would reduce static efficiency by effectively preventing lower cost non-firm generation from being dispatched.

At a practical level, it would be difficult for non-firm generators to anticipate when relevant constraints may bind so as to make timely reoffers as required. Constraints may bind or unbind from time to time due to changes in transmission (e.g. unplanned outages), demand or dispatch (e.g. due to reoffers from other generators). The rebidding of non-firm generators occasioned by the International Power proposal would exacerbate this uncertainty. For example, if several non-firm generators participate in a binding constraint, a rebid by a "first mover" may unbind the constraint, allowing the remaining generators to continue to be dispatched. This would lead to games of "chicken": i.e. trying to avoid being the first mover.

Power stations with zero firm access may have to shut down when constraints bind and may take several hours to restart. This could potentially endanger supply security or reliability: e.g. if this occurs shortly before a peak demand period.

Settlement by TNSP rather than AEMO

In the International Power model, to the extent that a non-firm generator offers during the binding of a relevant constraint, it must pay a penalty to the TNSP. The TNSP must use this penalty fund to compensate firm generators who are constrained off as a result.

In the OFA package, there is a similar compensation fund, but this is settled by AEMO. The AEMC prefers this for reasons of practicality and efficiency: AEMO already has settlement infrastructure in place; TNSPs do not. Firm access payments would be likely to offset other payments through settlement, so AEMO could make a net payment.

Penalties on non-firm generators based on gross revenue

The International Power proposal for calculating penalties on non-firm generators is not explained in detail. The AEMC's interpretation is that a non-firm generator would have its gross spot revenue confiscated by the TNSP: i.e. its dispatched output multiplied by the NEM spot price.

This breaches the “no regrets” principle adopted in the AEMC package, which states that a non-firm generator should be no worse off having been dispatched (and paying a penalty) than if it had chosen not to be dispatched (by re-offering). Under the International Power proposal, the non-firm generator would be worse off because it incurs fuel costs but receives no net AEMO revenue. The “no regrets” principle was adopted so as to maximise static efficiency and to prevent the sort of disorderly bidding behaviour described above.

Furthermore, if a constrained off firm generator received compensation based on its forgone gross spot revenue, this would ignore its fuel cost savings from not generating. This would represent a windfall gain, as the generator would actually be better off as a result of being constrained off. This would decrease certainty for firm generators, as the timing and magnitude of such windfalls would be uncertain.

In the OFA model, the compensation through access settlement would be based on flowgate prices, which implicitly recognise the offer prices of local generators. Dispatched generators would receive at least their offer price. Non-firm generators should have no regrets from being dispatched, so long as their offer prices cover their operating costs. Constrained-off firm generators would receive the flowgate price, which should at least equal the margin they would have earned by being dispatched.

A.4.2 LYMMCo and AGL

LYMMCo and AGL supported a variation on the International Power model, with the following additional characteristics:

- implementation of the package 2 congestion pricing mechanism to address disorderly bidding; and
- inclusion of the uplift payment, as described in the national locational marginal pricing model of package 5, to provide fully firm access.

Congestion pricing mechanism

As has already been noted, unlike package 4 in the First Interim Report, the OFA model functions as a congestion pricing mechanism in the absence of any firm generators, with entitlements allocated on the basis of offered availability.

Fully firm access through uplift payment

The OFA model does not aim to provide fully firm access, but allows generators instead to procure super-firm access to increase their effective access level, so differs from the LYMMCo/AGL proposal in this respect. The Commission does not consider that it is appropriate for consumers to bear the cost of providing fully firm access, either through an uplift charge on load, or by planning the transmission network to such a level of redundancy that the level of network access did not vary with transmission conditions such as outages.

A.4.3 AER

The following table compares the AER access model with the OFA model as it is described in chapter 3 of this report. They are broadly consistent.

The areas of inconsistency, and reasons for the different approach taken by the AEMC in the OFA model, are discussed below.

TNSP planning standard

The AER appeared to envisage a process in which AEMO – rather than the TNSP – would determine what new network assets (if any) must be developed in order that new access rights may be issued. That approach would – in the AER’s view – allow the asset development process to be contestable. Thus the generator receiving the access rights, and paying for the new assets, should be able to obtain a competitive price.

The Commission's preferred approach to pricing reflects the changes to a TNSP's investment plans that result over the duration of the access term. Generators should be liable for all these costs; not just those incurred in providing rights on the first day of the access term. Further, the Commission considers that allowing generators to provide assets deep in the transmission network is unlikely to be either practical or efficient.

Instead, the OFA model introduces a new planning and operating standard for TNSPs: the firm access standard. This approach is favoured as it is consistent with transmission planning on the demand-side, where TNSPs are required to plan the network to meet reliability standards. The costs of doing so are reflected to the generator through the LRIC pricing methodology over the full term of the access rights. The Commission also considers that TNSPs are best placed to make investment decisions, as this better allows for the optimisation of operating practices and investment.

Table A.2 Comparison of AER and OFA access models

Model element	Consistency	AER approach	OFA approach
Optional firm access right	Consistent	Generators choose the level of access they wish to purchase, so can be partially firm.	Same as AER.
Access charge	Consistent	Generators pay TNSPs for the cost of providing firm access.	Same as AER.
Dispatch	Consistent	No change to current dispatch process.	Same as AER.
Settlement	Consistent	Settlement based on constraint support price and constraint support contract similar to package 2 shared access congestion pricing.	Same as AER.
Tradeability of access rights	Consistent	Access rights should be tradeable.	Same as AER.
Access pricing	Inconsistent	A one-off access charge, based on a deep connection charges, would be payable at access start. Generators may arrange for deep connection assets to be provided contestably.	Access charges would be based on a long run incremental pricing methodology, which differs from a deep connection charge. The default payment profile would be an annual charge. The provision of assets required to underpin firm access would not be contestable.
TNSP planning standard	Inconsistent	AEMO approves TNSP issuing new access rights.	New firm access standard introduced.

Access pricing

As noted above, the OFA model features use of the LRIC access pricing methodology. For more detail regarding the ways in which this differs from a deep connection charge, and reasons why it has been preferred in the OFA model, please see section 6.3.1 of the staff Technical Report.

A.4.4 AEMO

The following table compares the AEMO access model with the OFA model as it is described in chapter 3 of this report. They are consistent in most respects.

The main areas of inconsistency, and reasons for the different approach taken by the AEMC in the OFA model, are discussed below.

Party issuing access rights

Under AEMO's model, access rights would be issued by a national network planner, which would procure network capacity from TNSPs (if this was not provided by generators themselves). As discussed in chapter 5, the Commission does not support the concept of a national planner/procurer. The OFA model therefore involves generators procuring access rights from their local TNSP.

TNSP incentives

AEMO suggested that its model would include an incentive regime that would focus on operational outcomes as measured by the firmness of the rights offered. This approach is also a feature of the OFA model. However, the Commission considers it important for this regime to be applied to TNSPs which are responsible for both investment and operational decisions, given that operational performance is inextricably linked to earlier investment decisions in terms of the specification and configuration of assets.

Table A.3 Comparison of AEMO and OFA access models

Model element	Consistency	AEMO approach	OFA approach
Optional firm access right	Consistent	Generators choose the level of access they wish to purchase, so can be partially firm.	Same as AEMO.
Settlement	Consistent	Generators holding access rights would receive payment or compensation from other generators when access is constrained. There are a range of choices to be made in how the scheme is administered and how prices, shadow prices or other financial compensation levels would be set.	Generators whose usage of a flowgate exceeds their entitlement automatically, through access settlement, compensate holders of firm access whose entitlement exceeds usage. The access payment is based on the flowgate price.
Tradeability of access	Consistent	Access rights should be tradeable.	Same as AEMO.
Transition	Consistent	Existing levels of access would be grandfathered and then traded between parties, or could be assigned dynamically.	Existing generators would receive a level of transitional access that would be sculpted back over time. Transitional access could be traded. The mechanism for allocating transitional access would be determined as part of implementation.
Firm access standard	Consistent	Access rights could be expressed through the specification and maintenance of standards for transfer capacity across all parts of the grid, or specified at certain points in the supply chain.	TNSPs are required to ensure that, in real time, they have sufficient available transmission capacity to provide at least the minimum level of access specified in the firm access standard.
TNSP incentives	Partially consistent	Access rights would be coupled with an incentive regime that would focus on operational outcomes as measured by the firmness of the rights offered.	Incentives expose TNSPs to some part of the cost to firm generators of transmission capacity being less than that required by the firm access standard. This mechanism will incentivise both TNSPs' planning and operational decisions, in recognition of their interdependency.

Model element	Consistency	AEMO approach	OFA approach
Party issuing access rights	Inconsistent	Generator procures firm access from national network planner.	Generator procures firm access from local TNSP.

A.4.5 MEU

The MEU proposed a model that appears to draw from three other models: the third and fourth packages from the AEMC's First Interim Report, and the existing funded augmentation model. The MEU model is not fully developed, and therefore lacks a degree of clarity as to exactly which elements of the three models it includes. In that respect, it is difficult to fully evaluate the MEU model alongside the OFA model. Instead, elements of similarity to its antecedents are identified below.

Model overview

The model aims to find a workable trade-off between two competing objectives:

- to signal to new generators the most efficient location for connection to the transmission network, taking into account both generation and transmission costs; and
- low entry barriers to new generation, so as to promote continuing generation competition, to the benefit of consumers.

Efficiency would be best promoted by charging the new entrant generator the full costs that it imposes on the TNSP, and on other generators, through its choice of connection location. However, the MEU sees this as creating an excessive barrier to entry. Therefore, its model proposes only to impose part of the cost on the new generator, with the remainder of the cost shared amongst existing generators who “benefit” from any transmission expansion. It is acknowledged by the MEU that this dilutes the locational signal to some extent.

The other main objective of the MEU model is to promote efficient expansion of the transmission network. The MEU model places responsibility on AEMO – and not the TNSP – to identify the appropriate transmission expansion. In making this decision, AEMO would seek advice from relevant generators – the new generators and affected existing generators – as to the level of access they require or (equivalently) the level of congestion they would be prepared to bear.

Comparison to generator reliability standards

This model has strong similarities to the third package of reforms from the First Interim Report - generator reliability standards. Two substantive differences are: firstly, that transmission expansion is planned by AEMO; and secondly, that AEMO explicitly takes generator access preferences into account. That second difference resembles the philosophy of the fourth package of reforms from the First Interim Report and is discussed in the next section.

Another difference from the generator reliability standards model is that the generator transmission charges are predicated explicitly on actual transmission expansion costs, so in that sense they have similarities to a deep connection charge. However, unlike a deep connection charge, the charges are not one-off: charges may be levied repeatedly on generators each time a nearby transmission expansion occurs. Thus, the charging regime appears to be a hybrid of generator TUOS and a deep connection charge.

Comparison to regional optional firm access

Since, in the MEU model, AEMO is required to take into account generator access preferences in planning transmission expansion, logically the model should provide that:

- the allocation of the expansion costs between generators is predicated on each generator's stated preferred access level: e.g. generators who do not require firm access should not contribute to the cost; and

- subsequent congestion costs should similarly be allocated based on these preferred access levels, with costs allocated primarily to those selecting non-firm access.

Although these elements are not clear from the MEU's submission, the AEMC sought further clarification from the MEU which supports this understanding of the MEU model.

The inclusion of these elements makes the MEU model quite similar to the AEMC’s regional optional firm access model. The essential difference seems to be that, whereas in the regional optional firm access model a generator contracts for firm access for a specific access term (probably, but not necessarily, a long term), under the MEU model there is implicitly an access term that lasts only until the next nearby new entrant generator. At that point, each generator (new and existing) will select a new preferred level of access and be allocated future congestion costs and any new expansion costs and accordingly.

Comparison to existing funded augmentations

With respect to implicit access terms being limited by subsequent generator entry, the MEU model has some similarities to the existing situation whereby a generator – or coalition of generators – can fund a transmission expansion in order to gain the benefit of reduced congestion, but with no guarantee that a future generator will not connect and cause renewed congestion. However, the MEU submission notes that, if a new generator did connect, it would be allocated – retrospectively – a share of the historical expansion cost, unlike with existing “funded augmentations”.

B Additional detail on proposals for extensions

This appendix provides further detail on three elements of our proposals for the provision of extensions, as set out in chapter 6:

- our analysis of whether there is workable competition in the provision of extensions;
- the framework for gaining exemption from the AER from the requirement to register as a TNSP; and
- the applicability of Part IIIA of the Competition and Consumer Act 2010 to access to extensions.

B.1 Workable Competition in the Service Delivery Chain for Extensions

Chapter 6 set out the service delivery chain for extensions and explained the Commission's view that there is workable competition for the provision of some elements of the chain, but that TNSPs are currently the only provider offering an end-to-end service. This Appendix sets out a more detailed analysis of whether there is workable competition in each element of the provision of extensions.

Grid Australia considers that extensions are contestable, and so can be provided as a non-regulated transmission service.[274] However, we consider that in order for the provision of extensions to be entirely unregulated, there must be both contestability and workable competition.

It is therefore useful to define both "contestability" and "workable competition". The definition of "contestable" in the NER provides limited guidance, simply stating that a transmission service is contestable if the laws of the relevant jurisdiction permit it to be provided by more than one TNSP "as a contestable service or on a competitive basis". However, for the purposes of this report we define contestability as whether it is possible for the extensions to be provided by more than one party. That is, does legislation and regulation allow any parties other than the incumbent TNSP to provide extensions in the NEM?

Workable competition is where there is sufficient rivalry between firms to ensure that they strive to deliver the goods and services that their customers demand, at least cost. While firms may have a degree of market power, this will not be either substantial or sustainable and will be subject to competitive erosion over time. In other words, competition will drive the market towards efficient outcomes over time.

274 Grid Australia, *Categorisation of Transmission Service Guideline*, version 1.0, August 2010, p. 7.

B.1.1 Assessment of the Workable Competition in the Provision of Extensions

We have assessed whether extensions are provided in a workably competitive market. In order to undertake this assessment we adopt the framework proposed by the Ministerial Council on Energy's (MCE's) Expert Panel on Energy Access Pricing (and which was set out in the First Interim Report).[275] This can determine the extent of market power associated with the supply of a network service, which allows assessment of whether the market is workably competitive or not. This involves the consideration of five factors, namely:

- presence of entry barriers – if there are barriers to entry the service provider may be insulated from competition, either from actual rivals or the fear of potential entry;
- presence of network externalities – electricity network services exhibit strong interdependencies, and so NSPs can benefit from significant cost advantages;
- presence of countervailing power – customers should have sufficient size and negotiating power in order to mitigate a NSP's market power in the negotiation of terms and conditions of access;
- presence of competition substitution possibilities – if there are alternatives for customers to use, then the market power of the NSP is limited; and
- degree of information asymmetry – differences in levels of information between the NSP and customers can be a source of market power, since it leaves uninformed users at a disadvantage.

We consider each of the five criteria above, in assessing whether there is workable competition in the elements associated with the provision of extensions.

Presence of Entry Barriers

Legislative and regulatory requirements can create barriers to entry. There are three requirements that occur in relation to ownership of extensions, namely:

- a requirement to be a registered TNSP in order to own, operate and control the extension;
- state-based licensing requirements in relation to owning and operating electricity transmission; and
- the need for land acquisition powers to obtain the necessary easements for the land over which the extension will be constructed.

In relation to the requirement to be a registered TNSP, clause 2.5.1 of the NER specifies that parties must be registered as a TNSP – but that they have the ability to gain

275 These criteria are also reflected in the NEL as "form of regulation factors".

exemption from the AER from the requirement to register. This exemption process is not unduly onerous, and is discussed in further detail in section B.3.1 below.

In relation to the second requirement, all states except NSW allow parties other than the incumbent TNSP to gain transmission licences. In every state (apart from NSW) parties can simply purchase a "licence" from the state regulator, and pay an annual fee to maintain this.

We note that in Queensland connecting parties can gain “special authority” from the Queensland Electricity Regulator in order to own transmission lines – with this essentially being an exemption from the requirement to obtain a licence.[276]

The third requirement is the potentially the most substantial barrier to entry. While some government owned and established private generators have compulsion rights to land, new generators and other third party providers typically do not. This is likely to be a significant barrier to entry for parties providing extensions (with this becoming compounded as the length of the line and so need for land increases). Indeed, TNSPs can, in some circumstances, use existing easements for providing extensions.

The powers of land acquisition in each of the NEM jurisdictions is detailed in the Table B1. In summary, the arrangements for acquiring land differ depending on the jurisdiction, specifically:

- in NSW only government owned transmission network operators (i.e. TransGrid) can acquire land (with Ministerial approval);
- in Queensland any licensed transmission entity can acquire land. For parties other than Powerlink, however, this requires additional Ministerial approval; and
- in Victoria, South Australia and Tasmania all licensed electricity entities (whether for transmission, distribution or generation) can acquire land for the purpose of carrying out their operations (albeit this may be subject to some form of Ministerial approval).

276 A “special authority” is obtained upon application to the Queensland Electricity Regulator. It is granted where the electricity facilities are “incidental” to the company’s main business. This is relative simple to obtain, but requires payment of a (small) annual fee.

Table B1: Powers of Land Acquisition with the NEM

	Queensland	NSW	Victoria	South Australia	Tasmania
State-based licensing requirements to operate part of a transmission network	• Electricity Act 1994 requires an "authority" to operate a transmission network • parties can also instead gain “special approval” from the Queensland Electricity Regulator • these are granted where electricity network is “incidental” to the core business	• no licence provisions for transmission • the Energy Services Corporations Act only gives only TransGrid powers as an “energy transmission operator” • under s.13 the Governor can amend the Act to add more corporations to be constituted as transmission operators	• under the Electricity Industry Act 2000, a licence is required to engage in transmission unless that person is exempt • ESC can grant generation, distribution and transmission licenses • currently only SPI Powernet has a transmission licence	• Electricity Act 1996 requires a licence to operate a transmission network, with this being operated in accordance with safety, reliability etc • ESCOSA grants transmission licences – currently ElectraNet has the system control & transmission licence, while BHP Billiton and OZ Minerals have off-grid transmission licences	• under Electricity Supply Industry Act section 17, Part 3- a licence is required for transmission of electricity • OTTER can issue licences • currently only Transend & Basslink have licences
Desirability of possessing land acquisition powers to obtain the necessary easements for the land over which the extension will be constructed	• any licensed transmission entity can acquire land • Powerlink is a “constructing authority” under the Electricity Act and so can acquire land	• only government owned transmission network operators (i.e. TransGrid) have powers to compulsorily acquire land with Ministerial approval	• the statutory powers to acquire land are the same for any person that holds a generation, transmission or distribution licence issued by ESC, but the acquisition must	• electricity entities (licensed parties) have the power to compulsorily acquire land, with Ministerial approval • any other individuals have to acquire land	• electricity entities (licensed parties) have the power to compulsorily acquire land with Ministerial approval • if another entity had government support,

	Queensland	NSW	Victoria	South Australia	Tasmania
	• other transmission authorities who wish to compulsorily acquire land/easements can gain “constructing authority” under the Electricity Act with Ministerial approval • if works are for infrastructure facility of significance, then the Government has powers to acquire land • any other individuals would have to acquire land as with any other person i.e. voluntary agreements will need to be negotiated	• any other individuals would have to acquire land as with any other person i.e. voluntary agreements will need to be negotiated	be approved by the Governor in Council • if the relevant project is of State or regional significance then the Government has powers to compulsorily acquire land for the purposes of that project • if an individual is not a licensee under the Electricity Act and does not have government support, then acquisition of land would occur as with any other person i.e. voluntary agreements will need to be negotiated	as with any other person i.e. voluntary agreements need to be negotiated	then the Minister could acquire land for it to use • any other individuals have to acquire land as with any other person i.e. voluntary agreements need to be negotiated
Any requirement to be a registered TNSP in order to own, operate and control the extension	Parties must either be: • registered as a TNSP; or • gain exemption from the AER from the requirement to be a registered TNSP, and/or from the technical requirements in Chapter 5 of the NER				

The second type of entry barrier relates to economies of scale. TNSPs may have competitive advantages because they provide a significant number of transmission assets in their jurisdiction.[277] In other words, providing extensions for a large number of parties results in cost savings. For example, it is cheaper to procure and erect many transmission towers, as opposed to one. We also understand that there may be economies of scale associated with reducing risk – e.g. insurance costs are reduced if multiple lines are insured as opposed to one.[278]

Presence of Network Externalities

In addition to economies of scale in procurement of network assets, TNSPs also have competitive advantages in terms of economies of scope, experience and capability in providing network infrastructure services. In other words, given the provision of extensions is closely related to their existing core business and processes, it will be cheaper for them to provide associated services since there are shared costs. For example, businesses gain experience and cost savings for operating and maintenance of extensions, through the operation and maintenance they carry out on the shared network. For example, sending a contractor out to check the condition of multiple lines and substations in a location is cheaper than sending out a contractor to check just one line.

Moreover, TNSPs have vast experience and knowledge of the provision of transmission equipment, since they manage large networks across jurisdictions. This knowledge and experience means that they will benefit from significant time savings in terms of providing extensions. Moreover, they will be able to apply previous learnings to current experiences. For example, a TNSP will already know who to apply to for planning permissions, what the process is, what payments must be made and when etc. Large connecting load or generators would not benefit from these network externalities.

Presence of Countervailing Power

Customers (i.e. the connecting party) must have sufficient size and negotiating power in order to mitigate a TNSP's market power in the negotiation of terms and conditions of access. It is difficult to assess the extent of connecting parties' countervailing power. Indeed, no submissions commented on the extent that countervailing market power exists in the market for extensions.

The Commission considers that large loads and generators (e.g. vertically integrated energy companies) may have some degree of countervailing market power as the size and number of connections they require may constitute a significant volume of negotiated transmission services for TNSPs. These large load and generators may also

277 Any business that specialises in providing extensions could also benefit from these economies of scale. However, as noted, none of these businesses exist currently in the NEM.

278 MEU, First Interim Report submission, p. 33.

have gained countervailing power through their years of negotiating with TNSPs, and so obtaining information on the TNSP's business.

However, connections and extensions will still account for a relatively small proportion of the TNSP's total services provided i.e. including prescribed transmission services. In addition, smaller and less experienced parties (e.g. renewable generators) will not have any degree of countervailing market power since their business will be such a small proportion of the services provided by a TNSP. Moreover, these parties will likely not have had experience negotiating with the TNSP.

Presence of Competition Substitution Possibilities

It is largely accepted that the actual construction of the extension is provided in a workably competitive market. TNSPs typically contract out the construction of their assets, and so this is subject to a commercial bid process – whether run by the TNSP, or a third party. Indeed, this appears to be borne out in practice in the NEM – Grid Australia has submitted examples of 12 companies that have provided extensions.[279]

Figure 6.1 in chapter 6 of this report set out that for some elements there are a number of parties that can provide the service. For example, the entire project management associated with the provision of the transmission line can be undertaken by the TNSP, the connecting party or a contractor. However, as noted above the TNSP is the only provider that can undertake all of the elements involved with the provision of extensions.

Degree of Information Asymmetry

Information asymmetry may exist between the TNSP and the connecting party. This was noted by some submissions in that it is not clear that TNSPs are providing connection assets at the lowest possible cost.[280]

Conclusion

Extensions can be capable of being supplied by both the TNSP and third parties (with the exception of NSW) – and so can be considered "contestable". Indeed, this is evidenced in current examples in the NEM, with 12 extensions being owned by parties other than TNSPs. However, in virtually all cases these parties have only entered this market due to their related interests in generation or load.[281] We understand that in very few situations, parties have chosen to compete in the market to provide extensions.

279 PwC, *Case for Economic Regulation: Application to electricity transmission services*, A Report for Grid Australia, June 2012, pp. 18-19.

280 MEU, First Interim Report submission, pp. 35-36.

281 Related to this is the competitive tendering experience in Victoria, where SP AusNet has won 13 out of 15 tenders. This also suggests that there is little evidence of competitive tendering more generally in the NEM.

However, deciding whether extensions are "contestable" is not the same as considering whether they are provided in a workably competitive market, where there is a strong relationship between prices and costs.[282] While we conclude that provision of extensions is contestable in most states we do not consider that there is workable competition in this market. Significant market power concerns arise in the context of additional parties connecting to, and wanting to gain access to, extensions as we have outlined above.

We note that the extent of competition for the provision of extensions differs in the different jurisdictions across the NEM. Indeed, it can be considered as a spectrum, ranging from:

- the case of NSW (no competition), where no parties other than TransGrid can gain transmission licenses and so build extensions;[283] to
- the case of South Australia (most competition), where third parties can readily obtain transmission licenses and own and operate extensions.

However, even in states where legislation allows contestability for the provision of extensions, we consider that on balance the current situation in the NEM suggests that this does not occur in a workably competitive market. This is consistent with submissions, where connecting parties have only provided connection assets because there were no other options.

We note that the above analysis may differ on a case by case basis. For example, in some circumstances it will be more appropriate for the connecting party to undertake all of the planning permission and environmental approval applications. This is because the applications can cover all infrastructure involved e.g. the transmission line, the plant and roads. Moreover, the connecting party can more easily manage community expectations if all works are considered together. In other instances, the connecting party may wish to draw upon the TNSP's expertise in these areas to undertake the application. However, we still consider that in most cases (and jurisdictions) the TNSP will have an advantage in a large number of elements.

Nonetheless, in some cases a connecting party may choose to own an extension itself, or to contract with a third party to own and manage the extension. In such cases, the owner will be required to either register as a TNSP or gain exemption from the AER from the requirement to register. The following section sets out the types of exemption available and explains some of the detailed elements of our proposals.

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282 As Professor Alfred Kahn explains, "the single most widely accepted rule for the governance of the regulated industries is to regulate them in such a way as to produce the same results as would be produced by effective competition, if that were feasible". See: Kahn A, 1988, *The Economics of Regulation, Principles and Institutions*, Volume 1 – Economic Principles, p.17.

283 Grid Australia has cited 4 examples of extensions being owned by generators in NSW. However, these are all of immaterial length (the longest is 2km) and we understand these are considered part of the generator's facilities.

B.2 AER Exemptions

Clause 2.5.1(a) of the NER requires that only a licensed NSP own, control or operate a transmission or a distribution system unless exempted under clause 2.5.1(d) of the NER.[284] Exemptions are granted by the AER in accordance with guidelines published by them.[285] The AER may also impose conditions on an exemption, including conditions relating to standards and regulatory controls in place for the network, access and charging.

The AER has recently published a revised set of guidelines on network exemptions (which covers any electricity equipment owned by private individuals).[286] In this, it sets out that three classes of exemptions can be granted:

- deemed exemption – where parties (e.g. small shopping centres) that meet a certain set of criteria are automatically 'deemed' to be exempt. Here, there is no requirement for these parties to be registered;

- registrable exemption – where parties meeting a given set of criteria 'register' with the AER. There is no assessment by the AER of what specific conditions these parties should meet; and

- individual exemption – where parties do not conform to the above classes, and so apply to the AER for an individual exemption. The AER assesses these exemptions and imposes specific conditions on these parties.

If parties are found to be in breach of their exemption, and the accompanying conditions, then they face civil penalties under the rules. The two most relevant categories to this discussion are 'registrable' and 'individual' exemptions, with these discussed below.

B.2.1 Registrable Exemptions

There are ten categories of registrable exemptions that are set out in the Guidelines. The two categories of registrable exemption that are pertinent in this situation are:

- 'NRO1' - off-market energy generation connected to the NEM via a private electricity connection; and

- 'NRO2'- on-market energy generation connected to the NEM via a private electricity connection, where the energy generation installations required to be registered with AEMO under clause 2.5.2 of the NER.

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284 This is also contained in the NEL: Part 2, Division 1, s11(2).

285 We note that exemptions can be gained from the requirement to register as a TNSP and/or the technical requirements as set out in Chapter 5 of the Rules. We understand that all exemptions to date cover both of these components.

286 AER, *Electricity Network Service Provider Registration Exemption Guideline*, 16 December 2011.

Applicants must submit a series of information to the AER in order for a registrable exemption to be recorded. Additionally, there are a number of requirements that parties holding registrable exemptions must comply with:

- the networks must be installed, operated and maintained in accordance with the applicable requirements within the jurisdiction that the network is located;
- the network must have in place approved dispute resolution procedures that customers can access at no cost, or on a fee for service basis; and
- if it can be demonstrated that access to the NEM would not otherwise be available except at significant cost to the affected customers, the network may also service other parties on reasonable commercial terms.[287]

We understand that an alternative interpretation is that the generator does not consider that it needs to be exempted, since it considers these assets part of the "generating system". In these circumstances, access would be provided via private, commercial negotiations with the generator itself. There are no provisions for dispute resolution.

B.2.2 Individual Exemptions

In circumstances where registrable exemptions do not apply, applications for individual exemption may be made.[288] For example, two of the contestable lines cited by Grid Australia have been "exempted" by the AER from being required to register as a TNSP.[289] Both of these exemptions have provisions relating to access in their approvals as conditions that they must comply with:

- that applicants "shall allow access to their network on reasonable commercial terms to be negotiated with any party seeking access"; and
- "the applicant must promptly […] notify the AER if a third party seeks access to its network".

B.2.3 Interaction with Jurisdictional Regimes

Importantly, an AER exemption does not relieve private networks from having to comply with jurisdictional requirements. That is, private networks still have to comply with licences as granted by state bodies, and all applicable requirements within the jurisdiction in which the network is located for the safety or persons and property.

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287 AER, *Electricity Network Service Provider Registration Exemption Guideline*, 16 December 2011, p. 23.

288 Other examples of parties that have applied for individual exemption include the Victorian Desalination Plant.

289 Specifically, the Davenport to Olympic Dam 275kV line owned by BHP Billiton in South Australia; and the Olympic Dam to Prominent Hill 132 kV line owned and operated by Prominent Hill mine in South Australia.

B.2.4 Commission proposals

In chapter 6 we proposed that the "registered exemption" class should only apply to those generators that own a transmission line of immaterial length (e.g. less than 2 km).[290] Lines greater than this length would not be considered part of the generating system, and so would require "individual exemption" by the AER. Therefore, parties who wish to be exempt fall into one of the following situations:

- generators owning transmission line less than 2 km should fall into the "registrable exemption" category;
- generators owning transmission line greater than 2 km should gain an "individual exemption"; and
- other parties owning transmission line should gain an "individual exemption".

We also proposed that the Guidelines are clarified in order to make a number of explicit provisions related to access clearer. These conditions in the individual exemptions should include:

- requiring third party access to extensions to be explicitly contemplated, including that this should occur through a negotiate/arbitrate framework;
- requiring a more fully developed description of an appropriate dispute mechanism process (i.e. process for dispute resolution including appointment of an independent arbitrator), including a set of third party access principles that should be considered by an arbitrator;[291] and
- clarifying that if an extension (or any part of it) becomes part of the shared network then that extension (or the part of it) is no longer considered exempt.

This would ensure that there are arrangements in place setting out a process for both gaining third party access, and dealing with disputes that may arise in this context.

The following section considers whether access to extensions could alternatively be gained through the Competition and Consumer Act 2010.

B.3 Access under Part IIIA

Submissions have contemplated that access to extensions could be gained under Part IIIA of the Competition and Consumer Act 2010 (CCA).[292] Part IIIA of the CCA sets

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290 We have based this proposed cut-off point on our review of the current “contestable” extensions in the NEM. Of the 12 examples of non-TNSP owned extensions submitted by Grid Australia (see First Interim Report submission, pp. 39-40), two are 20km or above; all others are 2km or less.

291 This is consistent with the principles contained in the Competition Principles Agreement, which include that a dispute mechanism is to be embodied in the access regime.

292 TRUenergy, First Interim Report submission, p. 10; Grid Australia, First Interim Report submission, p. 42.

out provisions for access to services. We do not consider that this is a feasible prospect, for reasons we set out below.

B.3.1 Pathways for Access

There are three potential "pathways" to obtaining access under Part IIIA, specifically:

- declaration – if an asset is not already subject to an effective access regime, a prospective user may apply to the National Competition Council (NCC) to have the service declared. Declaration gives the access seeker the right to negotiate with the service provider, with provision for legally binding arbitration if negotiations are unsuccessful;
- access undertaking – under Part IIIA an asset owner can submit a voluntary access undertaking to the Australian Competition and Consumer Commission (ACCC) for approval. Amongst other things, the access undertaking must set out the terms and conditions upon which access will be provided, and the manner in which the negotiate-arbitrate model will operate; or
- certification of a state or territory access regime – a state or territory can apply to the NCC for certification of a particular regime. The regime must comply with certain principles contained in the Competition Principles Agreement and the objectives of Part IIIA of the CCA.

The most pertinent "pathway" in this situation is for a third party seeking access to an extension to apply to the NCC to have the service declared i.e. the first pathway above. We discuss this pathway further below.

B.3.2 Declaration of a Service

Under Part IIIA, the NCC cannot recommend that a service is declared unless it is satisfied that the following criteria are met:

- criterion (a) – access (or increased access) to the service would promote a material increase in competition in at least one market (whether or not in Australia), other than the market for the service;
- criterion (b) – that it would be uneconomical to develop another facility to provide the service;
- criterion (c) – that the facility is of national significance having regard to: the size of the facility, or the importance of the facility to constitutional trade or commerce, or the importance of the facility to the national economy;
- criterion (e) – that access to the service is not already the subject of a declared access regime under Division 6 of Part IIIA; and

- criterion (f) – that access (or increased access) to the service would not be contrary to the public interest.

We consider that there would be considerable difficulties in convincing the NCC that these criteria are met for extensions, for example:

- if the related markets are defined relatively broadly (which they may well be), then access would not promote a material increase in competition in any of those markets, in which case criterion (a) would not be met;

- in the case of load, if the price of the relevant raw material being mined (iron ore, coking coal etc) in the downstream market is forecast to be 'high', then it will be privately profitable to duplicate the line, in which case criterion (b) won't be met;[293]

- a transmission line is unlikely to be considered of national significance,[294] in which case criterion (c) will not be met; and

- if criteria (a) through (c) are not met, then access would be contrary to the public interest, and so criterion (f) won't be met.

Lastly, we note that obtaining declaration is not as simple as the NCC recommending declaration of the service. The actual declaration must be made by the Federal Treasurer (who could ultimately choose not to declare the service). The decision is also subject to numerous appeals, and so may be a lengthy and contentious process.[295]

The Commission considers it would be difficult for the majority of extensions to meet these criteria, and is therefore proposing to clarify the third party access conditions of AER exemptions, as explained above.

293 This definition of "uneconomic to duplicate" as being based on a "privately profitable" test was a consequence of the Full Federal Court's decision in Fortescue's application to gain access to Rio Tinto's assets in the Pilbara. Previously, a "social benefit" test had been applied where it was assessed whether the infrastructure was capable of meeting demand for the relevant service (including third party demand) at lower cost than two or more facilities. All costs (including production, social and consequential costs) were used in the assessment.

294 Some stakeholders have commented that transmission lines may meet this criterion. However, we consider that this is unlikely even in instances of very long and/or large capacity transmission lines.

295 For example, the current Pilbara third party access applications being considered by the High Court were submitted to the NCC in 2004. Accordingly, the process for deciding whether or not the network is to be declared (or not) will have taken upwards of eight years.