REVIEW

Australian Energy Market Commission

FIRST INTERIM REPORT: OVERVIEW REPORT

Transmission Frameworks Review

Commissioners

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17 November 2011

Reference: EPR0019
First Interim Report: Overview Report

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Reference: EPR0019

Citation

AEMC 2011, *Transmission Frameworks Review*, First Interim Report: Overview Report, 17 November 2011, Sydney.

About the AEMC

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

Contents

1 Introduction and background

Transmission of electrical energy from generators to end use customers is central to the existence and efficient functioning of the National Electricity Market (NEM).

Dispersed generation from a range of sources and a market spread over such a large geographic area mean that planning, investment in and operation of the transmission network is pivotal to the effective operation of the NEM and delivering efficient prices to customers.

The arrangements for transmission in the NEM have been progressively refined since its commencement in 1998, but still substantially reflect the jurisdictionally based arrangements that preceded the national market.

One of the purposes of the Transmission Frameworks Review (the "review") is to test whether these arrangements remain the most workably efficient and effective for taking the NEM forward into future decades. This is a particularly important question now, with significant but uncertain changes in generation fuel mix and location highly likely, in part as a result of climate change policies.

The first interim report for the review does not make recommendations for reform but sets out for stakeholder consideration a series of potential alternate paths forward for development of transmission arrangements in the NEM.

This overview report is provided by the Australian Energy Market Commission (AEMC or Commission). It seeks to set out the key issues raised in the first interim report in a simplified or summary manner. Its purpose is to provide an overview of the contents of the full report. It should not be used as a substitute for considering or responding to Commission policy proposals as the cost of simplicity is a loss of some important context and detail.

The review

The review has been characterised by a very high level of stakeholder engagement, as well as a marked diversity of views about the effectiveness and efficiency of current frameworks, the need for change, and alternate reform paths. The Commission's thinking in conducting the review has been informed by the National Electricity Objective (NEO) together with some specific principles for transmission set out by the Council of Australian Governments in 2007.

The Commission will ultimately be recommending transmission frameworks that it considers are most likely to optimise investment and operational decisions across generation and transmission in a manner that minimises the overall, long term costs to consumers, while facilitating continued security and reliability of supply. Long term costs will be influenced by how much and where transmission is built and the effectiveness of incentives for its efficient planning, operation and utilisation. They will also be influenced by the type and location of generation and loads that connect and the incentives for doing so efficiently.

The case for reform

Whether substantial reform of NEM transmission frameworks is required remains an open question at this stage of the review. Stakeholders, including generators, have expressed widely varying views on the workability and efficiency of current arrangements.

However to date limited evidence has been provided which demonstrates the materiality of any current or anticipated inefficiencies associated with the existing arrangements. Any significant framework change will carry implementation costs and risks which need to be proportionate to and tested against any risks of retaining current frameworks.

Pathways to reform

The first interim report outlines five alternate policy packages which represent a range of approaches to structuring the law, rules, financial obligations and institutions that provide the framework within which transmission in the NEM operates. They are not the only approaches that could be considered. They draw on input from stakeholders, experience in other markets and the Commission’s own analysis.

As this review has progressed it has become increasingly clear that key elements of transmission frameworks, such as the nature of generator access rights, charging for use of the transmission system, planning and the incidence of and responses to congestion are highly inter-related. Change to any of these key elements will need to take account of the impacts on the others. For example, the nature of access rights (if any) that a generator has to use the transmission network needs to be considered concurrently with the nature of charges that generators might pay for use of the network.

Each of the five proposed policy packages therefore addresses these key elements of transmission frameworks and, in the Commission's view, does so in an internally consistent manner. There are variations that might be proposed by stakeholders to some or all of the policy packages. However, the Commission urges stakeholders responding to this paper to avoid picking preferred elements out of several packages and attempting to combine them unless they can demonstrate that the internal consistency of a package is maintained.

Three of the proposed packages have direct implications for the way in which the transmission network will be planned and the institutions that are required to support these arrangements, which are discussed as part of each of those packages. In contrast, the remaining two packages do not require changes to the planning or institutional arrangements in order to effect their implementation. However, there may be some enhancements that could be made to the existing arrangements to improve certain aspects. These options are presented separately to provide clarity that they are not required to maintain the consistency of any package, but could be implemented with a number of the proposed packages.

The first interim report provides a number of options for reforms to the arrangements for connecting generators and large load to the transmission network. As with some of the options for changing planning arrangements, proposals for connections are somewhat separable and could apply to any of the packages.

The next phase of the review will consider which of these policy package options is most likely to promote the achievement of the NEO. This process will be informed by stakeholder submissions to this review and by comparing the packages against our assessment framework, as set out in chapter 3 of the first interim report and summarised below. We intend to narrow these packages down to one or two preferred options and also set out our preferred options for reform to the planning and connections arrangements in the second interim report. The next report will also provide a more detailed description and assessment of our preferred option(s).

2 The first interim report

The first interim report sets out for stakeholder consideration and feedback some alternate paths to reform of transmission arrangements in the NEM in two broad streams.

First it outlines five alternate, future development pathways comprised of five internally consistent "packages" of policy reform, some of which are very different to the current NEM arrangements. Each of these reforms reflects a different approach to the future long term development of transmission frameworks. The proposed packages are described at a conceptual level and are accompanied by a relatively high level qualitative assessment of their relative strengths and weaknesses.

Central to each package is the nature of generator network access that it provides for, which in turn shapes the nature of charging, planning and in some cases institutional arrangements proposed in the package. The Commission stresses that at this stage it has not identified any preferred package.

At a second level the report also sets out for feedback some proposals for improving current arrangements for NEM transmission planning and connections to the transmission network. In the case of planning these are proposals that could be progressed to enhance current frameworks which, in most cases, would be consistent with each of the broader policy packages. Additionally, a number of more substantial options for the reform of planning arrangements are discussed, based on stakeholder submissions to the review.

In relation to the connection of generators and large loads, the report sets out for consultation some analysis, conclusions and questions with a view to clarifying and improving current arrangements. This focuses on clarifying ambiguity in the National Electricity Rules (the rules) but, in addition, raises more fundamental questions about the nature of economic regulation of and access to connections and extensions. The three connections proposals presented represent varying degrees of regulatory intervention that might be considered to address apparent imbalances in bargaining power between Transmission Network Service Providers (TNSPs) and connecting parties.

Policy packages

As previously noted, the range of pathways to reform presented in the report reflects, in part, different responses to dealing with congestion risk and generator uncertainty of access.

Each of the five packages are described in detail in chapters 6 to 10 of the first interim report but are briefly described below and summarised in Table 2.1 of this overview. In the first interim report each package is described according to six key features[1]:

1 Note that for simplicity, these may not all be covered for each of the packages in this overview document. Please see the first interim report where greater detail or context is required.

- the definition of the type of access or service level to be provided by TNSPs to generators;
- the way in which access rights are assigned to generators;
- the way in which the type of access proposed in the package will influence dispatch of generation and transmission congestion and the way in which generators may be compensated if they are constrained off the transmission system;
- the charge that generators would pay for use of the transmission system (if any);
- any changes to the planning, investment and operational decisions are made by TNSPs; and
- any changes that are required to market institutional arrangements.

For details on how to respond to the first interim report, please see section 1.6 of the first interim report.

Table 2.1 Summary of the proposed packages

Package:	1: Open access	2: Open access with congestion pricing	3: Generator transmission standards	4: Regional optional firm access	5: National locational marginal pricing
Access/congestion	Generators have no firm level of access, no congestion pricing	Generators have no firm level of access, congestion is priced. All generators receive a proportion of congestion rents	Access defined by reliability standard for generators, no congestion pricing	Generators choose a quantity of firm access to the regional reference node	Generators are able to purchase fully firm rights to a national hub; non-firm generators exposed to congestion cost
Charging	No generator charge for use of the shared network	No generator charge for use of the shared network	All generators face a charge to reflect the cost of maintaining the standard	Firm generators pay a charge; no charge for non-firm generators but they are potentially liable for compensation	Rights purchased at auction, no charge for non-firm generators
Planning/institutions	No changes required (but enhancements possible)	No changes required (but enhancements possible)	TNSPs plan to new generator standard. Additional incentives required on TNSPs. Institutional arrangements to be considered e.g. who sets the standard. Further enhancements also possible	TNSPs plan to new standard for firm generators. Additional incentives required on TNSPs. Institutional arrangements need to be considered e.g. who sets the standard. Further enhancements also possible	Single (NEM-wide) TNSP plans to new standard for firm generators, investment funded by auction proceeds. Additional incentives required on TNSP

3 Assessment framework

As indicated above, there is no consensus amongst stakeholders on whether there is a case for significant change to transmission frameworks. At the end of this review the Commission will be seeking to recommend to the Ministerial Council on Energy (MCE) reforms to the transmission arrangements that would, in its view, be most likely to be workable, effective, efficient and stable over the medium to longer term. Recommended frameworks will need to be workable regardless of how the market, particularly the market for generation, develops over time. In the Commission’s view, trying to shape transmission frameworks around predictions of future technological and policy development is likely to lead to inefficient long term outcomes.

Chapter 3 of the first interim report sets out in some detail the outcomes we are seeking to achieve through robust, well-structured and targeted transmission frameworks, which will form the basis for comparing alternative packages against the existing arrangements. Consistent with promoting the NEO, the objective for this review is to ensure that investment and operational decisions across generation and transmission are optimised in such a way that minimises the expected total system costs borne by electricity consumers. Minimising total system costs implies that:

- TNSPs should have incentives to efficiently operate and invest in their networks. This means that TNSPs should ensure that existing capacity is used efficiently and that the network is expanded in an efficient and timely manner. Building transmission capacity that is not likely to be fully used because it is poorly located or sized will result in unnecessarily high prices. Similarly, insufficient transmission investment in an area can restrict generator competition, also leading to higher prices.

- Generators should have incentives to offer their energy at an efficient price and invest in new plant where and when efficient. This should occur when generators have access to a deep and liquid contract market and the transmission network supports a competitive generation sector.

- The set of policies or incentives that govern transmission decisions, and the market signals which influence generation decisions, should work together to provide a consistent overall framework. This framework should ensure that individual market participants have appropriate incentives to invest in, operate and use the network efficiently.

The Commission's assessment will take into account that any significant change away from existing transmission arrangements involves a degree of risk and is likely to result in implementation and transition costs. In assessing alternatives to current arrangements the capacity of existing frameworks to provide outcomes consistent with the objectives outlined above will be taken as a baseline. Proposals for change will need to be considered likely to result in materially more efficient outcomes to overcome transition and implementation costs and risks associated with moving away from current arrangements.

4 Summary of existing transmission arrangements

To place the proposals for reform in context, chapter 4 of the first interim report provides a brief overview of how the existing transmission arrangements operate. It also includes an explanation of some key terms.

There are a number of mechanisms that, together, support the planning, investment and operational functions of transmission businesses. These arrangements are intended to ensure that TNSPs will invest in, maintain and operate their networks in an efficient and transparent manner. Some of these arrangements are only recently implemented.

A brief outline of transmission's role in the NEM is discussed below followed by an introduction to a number of the key mechanisms within the existing arrangements. It also explains how generators' operation and investment decisions are influenced by transmission arrangements.

4.1 Introduction

Transmission networks form a key part of the electricity supply chain. They efficiently transport large amounts of electricity at high voltages from generators to distribution networks and large industrial customers. Distributors then convey the electricity at lower voltages to the millions of consumers who use it.

The transmission system also plays a crucial role in allowing generators to compete with each other so that consumers can be provided with electricity at the lowest cost. Transmission networks therefore underpin the efficient functioning of the NEM.

Figure 4.1 Electricity network

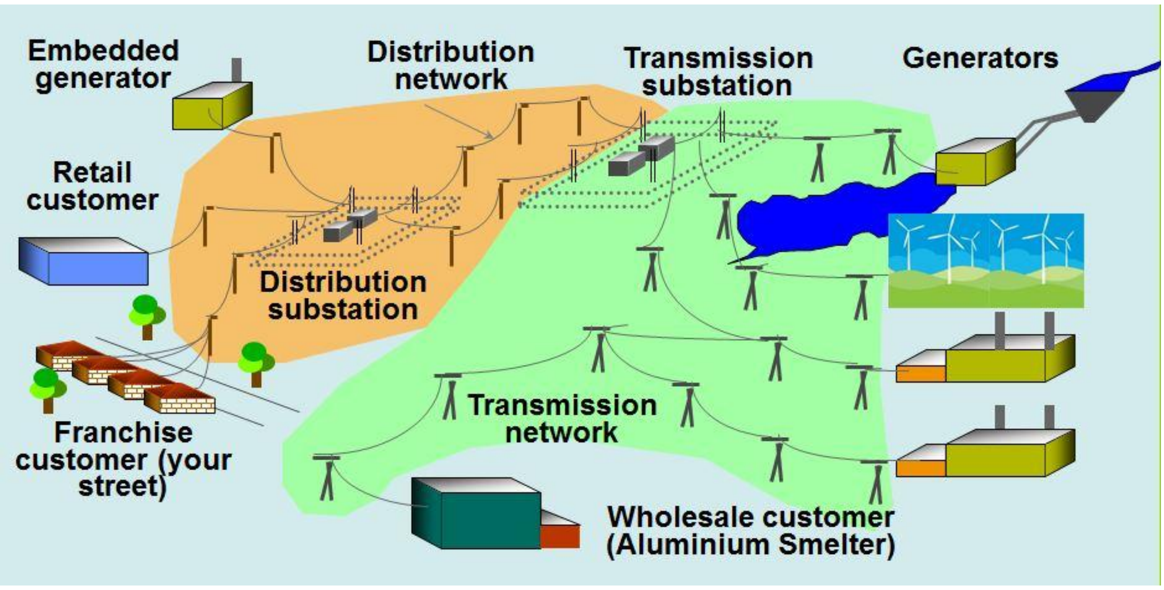


Figure 4.1 provides a simplified diagram of the physical electricity network from the point where electricity is generated through to where it is consumed, highlighting the role of transmission.

The total transmission system in the NEM is approximately 41,000km in length and covers an area from Queensland through to New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania. As can be seen in Figure 4.2, the transmission network is long and thin reflecting the location of, and distance between, major demand centres.

Figure 4.2 NEM transmission system

Source: Grid Australia website

The transmission system in the NEM is divided up between a number of TNSPs: generally, there is one TNSP per state, which owns and operates the transmission network in that jurisdiction. A key role is also played by the Australian Energy Market Operator (AEMO), which operates the market and has a number of responsibilities associated with transmission planning.

4.2 Transmission investment and operational arrangements

Transmission reliability standards

TNSPs are required to build and operate networks to meet power quality and reliability standards for the service delivered to load. These standards are embodied in the rules and jurisdictional instruments and differ between jurisdictions in both the level of the standard and the manner in which they are expressed: "deterministic";

"probabilistic"; or a "hybrid" form of standard.[2] The Commission has previously recommended a national framework to improve consistency and transparency of standards across jurisdictions.

National planning and inter-regional augmentation

The National Transmission Planner, a part of AEMO, has responsibility for identifying potential investments that may achieve efficient development of the grid through the National Transmission Network Development Plan. TNSPs publish annual planning reports which set out future developments and should link to the National Transmission Network Development Plan. The AEMC also has a Last Resort Planning Power which allows it to direct parties, under specific circumstances, to undertake cost benefit studies on inter-regional transmission projects.

The Regulatory Investment Test for Transmission

TNSPs are required to apply the Regulatory Investment Test for Transmission prior to making certain major transmission augmentations. The test requires TNSPs to use cost benefit analysis to identify the most economical way of delivering augmentations, through a mandated consultation process.

Revenue cap regulation

The revenue that may be earned by TNSPs is regulated by the Australian Energy Regulator (AER), generally in a manner that provides some financial incentive to minimise expenditure over a five year revenue control period. In Victoria AEMO plans and procures the transmission network and, as a not for profit organisation, is not subject to the same financial incentives.

Service Target Performance Incentive Scheme

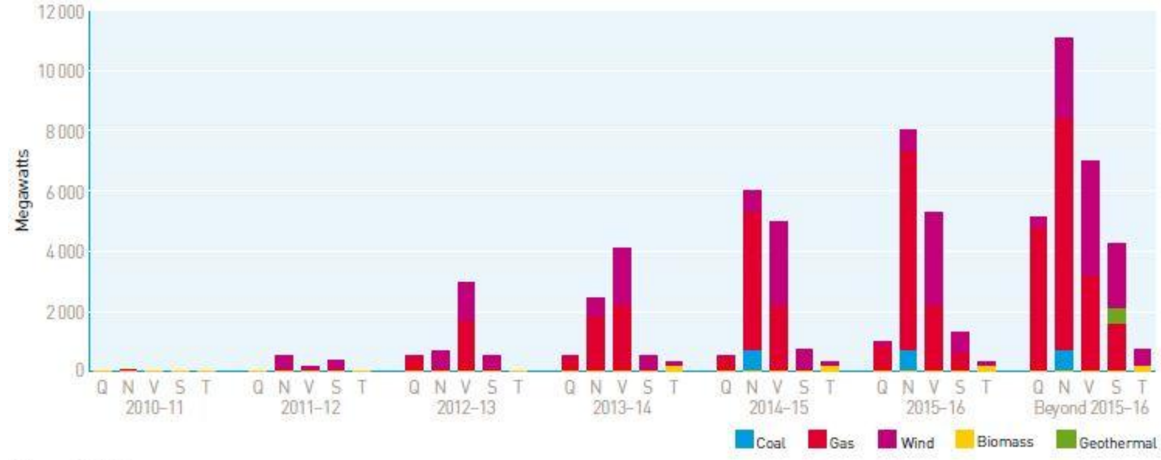
The Service Target Performance Incentive Scheme is a component of the revenue regulation of TNSPs by the AER. It provides a financial incentive for maintaining service standards and providing capacity when it is most valued by the market.

4.3 Current generator investment incentives

Going forward, a significant amount of new generation investment is expected to be built in the NEM. At June 2010, AEMO listed over 40,000 megawatts (MW) of proposed generator capacity in the NEM. This can be seen in Figure 4.3.

2 These different forms of standard are described in section 4.2.1 of the first interim report.

Figure 4.3 Proposed generation investment in the NEM, cumulative, June 2010



Source: AEMO.

Transmission arrangements influence generator behaviour, both in the long term via the investment decisions that they make, and in the shorter term via the prices and volumes in which they offer their energy into the market. The way in which generators respond to an absence of transmission network availability in the short and long run will influence the efficiency with which the energy market operates and, ultimately, the price that end-use customers pay.

Investing in generation requires confidence that the generator will be able to earn sufficient revenue over the long term to be profitable. Generally, this requires new generation to be underwritten by long term contracts or be built to supply a company's retail load. For this to be viable a generator needs to be able to access the "regional reference node" allowing it to export its output to the market. If the transmission network becomes congested, a generator may be unable to do this, exposing it to risk.

The risk of congestion varies across the transmission network and over time and is likely to be one of the factors a prospective generator considers when deciding where to build. Other energy market factors influencing location choice may include the cost of connecting, electrical losses, and regional price differences. Non market factors such as planning approval and access to fuel and cooling water are also likely to be significant locational signals that affect investment.

4.4 Current generator operational incentives

When constraints occur on the transmission network generators behind the constraint can have an incentive to offer their output at very low or negative prices, which do not reflect their underlying costs. They do this to try to maximise their dispatch knowing that the pool price they will actually receive will be set by other higher priced generators. This "disorderly bidding" can result in the dispatch of higher cost generation, leading to productive inefficiency.

5 Performance of existing transmission arrangements

5.1 Introduction

Throughout this review there has been significant diversity of views amongst stakeholders about the performance of current transmission frameworks and consequently the need for any change. Chapter 5 of the first interim report provides an assessment of the strengths and weaknesses of the existing frameworks, drawing from stakeholders' submissions. The chapter also presents the Commission's current views on the wide range of issues that have been raised.

The discussion about the effectiveness of current frameworks occurs in the context of the likely significant change that will occur in energy markets, largely as a result of climate change policies. Although changes in the mix and location of generation and associated transmission requirements are foreseeable, the specific outcomes are not. This makes it critical to shape transmission frameworks that can be responsive to a range of outcomes.

Some stakeholders consider current frameworks to be broadly appropriate, others consider that there is a need for more substantial reform to promote efficient investment and operational decisions by both TNSPs and generators.

There is significant divergence of views amongst generators which appears to be linked to location and ownership structure. Broadly, larger government-owned generators in Queensland and New South Wales (NSW) have viewed existing arrangements as appropriate. Victorian generators, all privately owned, have raised a number of concerns. What causes this different level of satisfaction with outcomes is not particularly clear from the evidence presented to date. The differences are explored in more detail in the first interim report but the key issues are briefly touched on below.

5.2 Efficient investment in and operation of transmission networks

The existing frameworks for planning of and investment in transmission differ significantly between jurisdictions, although there have been relatively recent market changes that have introduced common elements.

Planning for transmission is substantially driven by the standards of service delivery set for loads. In Victoria these are determined in a probabilistic manner, in Queensland and NSW in a deterministic manner, and in South Australia using a hybrid approach. Some stakeholders consider that these different approaches lead to significantly different outcomes, with probabilistic planning seen as lacking transparency but being more economically rigorous than deterministic standards. The Commission has previously recommended a national approach where standards are determined economically but expressed deterministically (the hybrid approach) to enhance transparency of standard setting.

National planning and inter-regional augmentation arrangements have been the subject of a range of stakeholder views, with some concern that the dispersed responsibility for inter-regional planning may lead to sub optimal outcomes. The Commission notes that much of the current framework is relatively new including the National Transmission Planner, National Transmission Network Development Plan, Regulatory Investment Test for Transmission and the Last Resort Planning Power. However, in response to stakeholder submissions, chapter 11 of the first interim report sets out some possible enhancements to these arrangements for consultation.

5.3 Efficient investment in and operation of generation

Stakeholders to this review and previous Commission reviews have been divided on the need for a charge to generators for use of the transmission system. Key arguments for a charge are that it signals to generators the costs they impose on different parts of the transmission network, potentially leading to more efficient decisions. Many existing generators have called for any charge to be imposed on new generators only, and for charges to be based on the cost of expanding the transmission system to maintain current generators level of access. Other stakeholders consider that this would be an unwarranted barrier to the entry of new generation.

The Commission notes that there are already a range of locational cost signals for new generators (outlined in 4.3 above). Whilst there may be some loss of efficiency in not having an explicit signal of transmission costs, it is not clear that the complexity of calculating an appropriate charge outweighs this under the current arrangements. However, if a firm access service is to be provided to generators, as in some of the alternative paths for transmission outlined in the report, a charge commensurate with that service should be levied on generators.

As noted in the previous section, congestion of the transmission network presents a risk to generators which may limit their ability to enter contracts. In turn, this may have a dampening effect on investment in new generation. Throughout this review there have been markedly divergent views amongst stakeholders about the materiality and cost of congestion, and the appropriate means of measuring these currently, let alone estimating future materiality and cost.

6 Package 1: An open access regime

6.1 Introduction

This first proposed policy package is substantially based on the arrangements that exist in practice in the NEM today. However it clarifies that there would be no avenue for generators to seek firmer transmission access rights. No generator charges would be imposed for using the transmission network.

This package is modelled on the current arrangements in the NEM and so represents the minimum change option.

6.2 Key features of an open access model

Access

Currently the NEM operates under an "open access" regime for generators. This means that generators have a right to connect to the transmission network, but no right to dispatch output across the network. In the absence of transmission constraints, if a generator is dispatched by AEMO, it can export its output.

When a transmission network constraint prevents a generator's dispatch it will suffer a loss of opportunity to earn revenue, even though it may be a low price bidder, and it will not receive any compensation.

The rules do contain provisions in clause 5.4A that imply generators can negotiate with a TNSP for firm access to the network and be compensated if access is unavailable. However, to our knowledge these provisions have never been used. Furthermore, as the analysis in chapter 6 of the first interim report sets out, in the Commission's view these arrangements cannot work in practice.

For a TNSP to agree to provide firm access with a generator would mean that the TNSP would have to either build additional transmission capacity to guarantee the generator access and/or pay compensation to the generator when it was unable to gain access.

The first of these alternatives is not practicable. If a TNSP built additional capacity, funded by the generator, another generator could, under an open access framework, locate nearby and utilise that capacity. Alternatively, paying compensation would require the TNSP to find a source of funds for the compensation, other than the generator in question. This is a matter the rules do not provide for.

For these reasons the Commission considers that either these provisions should be removed from the rules to clarify that the NEM operates as a fully open access regime or they should be replaced with a workable form of access. Packages 1 and 2 provide options for implementing the former, while mechanisms for allowing for forms of firm access are outlined in packages 3, 4 and 5.

Therefore under package 1 all generators would have the right to connect to the transmission network but the right to use the network would be determined by whether a generator's price offer resulted in it being dispatched by AEMO. Such dispatch occurs with AEMO having taken account of congestion restrictions.

Charging

This package does not include a charge for generators for their use of the transmission network. There may be a case for introducing a charge for the purposes of signalling to generators the costs they may impose on the transmission system through their locational decisions. However, under an open access regime, any inefficiency that might result from the lack of such a charge is likely to be outweighed by the difficulty in quantifying and charging for a particular generator's impact under an open access arrangement.

Planning

The feasibility of an open access model is predicated on the assumption that congestion would be built out in a timely manner where it is efficient to do so. This does not mean that all congestion should be built out, rather that congestion should be addressed where the benefits of doing so exceed the costs. Transmission planning and investment frameworks will therefore need to be appropriately responsive to support the efficient build out of congestion. As noted elsewhere in this report, much of the NEM planning frameworks are relatively new, but given the importance of effective planning arrangements under this package, some enhancement options are canvassed in chapter 11 of the first interim report.

6.3 Advantages and disadvantages of the open access model

An open access model has a number of benefits, such as providing a disincentive to locate in congested parts of the network and maintaining competitive pressures on generators. Further, implementation costs would be minimal as this model broadly reflects the existing approach to access (in practice).

However, these benefits must be weighed against the efficiency costs associated with such a regime, with generators exposed to uncertainty of dispatch. Uncertain dispatch can lead to dynamic efficiency costs such as a less liquid contract market and higher financing costs.

7 Package 2: Open access with congestion pricing

7.1 Introduction

The second package, like the first package, is based on the existing open access arrangements. It differs from the first package only by introducing a market wide mechanism to better maintain incentives for generators to bid in an economically efficient manner when the network is constrained. This mechanism has the effect of putting a value or "price on congestion" so that generators take account of it in constructing their offers.

Such mechanisms have been trialled in the NEM before and have been considered for broader implementation across all or part of the NEM in previous AEMC reviews. To date, a compelling case has not been made that the efficiency advantages that such a mechanism should bring would outweigh the additional complexity.

7.2 Key features of the congestion pricing model

Access

As with the first package, generators would have a right to connect to the network but would not have, or be able to negotiate for, a right of access across the transmission network. Rather, the right to use the network would be determined by whether a generator's price offer resulted in it being dispatched by AEMO.

The effect of congestion on generator behaviour

Currently, within a NEM region[3] all generators in each region receive the same regional reference price (adjusted for losses, which we will ignore for the purpose of this discussion). When congestion occurs within a region the true value of generation (but not the price) will vary across the region depending on which side of the constraint a generator is located.

Generators behind an intra-regional constraint cannot all be dispatched so, as discussed, they have an incentive to bid a very low or negative price that does not reflect their underlying cost of productions to try to maximise dispatch, resulting in negative market impacts.

These include the dispatch of higher cost generation ahead of lower cost generation, leading to productive inefficiencies. It can also have perverse effects across regional boundaries. This is caused when a generator, knowing they will receive the high price within their region, bids low in order to try to maximise dispatch despite congestion. This can displace cheaper generation in an adjoining region which, because it receives

3 A NEM region is the same as the state jurisdictions except for the Australian Capital Territory which is considered part of the New South Wales region of the NEM.

a different price, cannot compete in the same manner. This has the effect of pushing up prices unnecessarily and increasing the risks associated with inter-regional trading.

Congestion pricing mechanism

The congestion pricing mechanism presented in this package is termed the Shared Access Congestion Pricing (SACP) model. The focus of the model is to remove the current incentives for disorderly bidding by generators when there is congestion and therefore address the consequences of this behaviour.

The SACP model does not provide a long term solution to congestion, nor does it provide fixed rights to generators associated with compensation. Instead the SACP model exposes generators to the implicit price at the point they connect to the transmission network. It also provides a hedging instrument that is divided amongst the generators behind the constraint according to their capacity. This hedge varies in real time depending on network conditions .

The pricing aspect of the SACP model exposes generators to the marginal value of congestion, while the hedging element provides a measure of protection against the risks that arise as a result. If adopted, it would be intended that the SACP model be implemented across the NEM as a permanent change to the market design and would be integrated into the market dispatch mechanisms.

Charging

Under this package, as with package 1, there would be no transmission charge levied on generators.

Planning

There would be no fundamental changes to transmission planning, investment and institutional arrangements, other than the addition of functionality to the dispatch and settlement mechanisms to implement the SACP mechanism. As with package 1, this model depends on the effectiveness of planning arrangements to build out congestion when it is efficient to do so.

7.3 Advantages and disadvantages

The key advantage of the SACP model is that it should improve dispatch efficiency and thereby encourage more cost reflective bidding in the NEM. This could represent a significant benefit to the market, which could be achieved without fundamental reform to the NEM arrangements.

However, by virtue of the way in which hedges are allocated, the SACP model on its own does not strengthen locational signals relative to current arrangements. Consequently, concerns over the longer term impacts of congestion, such as the predictability of access for generators, are not addressed by this approach.

8 Package 3: Generator reliability standards

8.1 Introduction

The third proposed policy package would introduce transmission reliability standards for generators. This is the first of the packages that would introduce a firmer level of access for generators. The model is derived from existing arrangements for load, whereby TNSPs are required to plan their networks to meet defined transmission network reliability standards.

TNSPs would have to meet minimum reliability standards for generator use of the transmission network, in a similar way to existing load reliability standards. This would give generators increased transparency and certainty about their level of access to transmission, for which they would pay a charge. The standards would be independently set, with accompanying financial incentives on TNSPs.

Current drivers of transmission investment

Under current arrangements the primary driver of transmission investment is the need to meet reliability standards for load (consumers). TNSPs can invest in upgrades other than to meet these load standards where there are net market benefits, as assessed under the Regulatory Investment Test for Transmission. However, the benefits to generators of certainty of access to the market are not factored into the assessment so there are limited drivers for transmission investment to build out congestion where doing so is not necessary to meet load reliability standards.

8.2 Key features of generator reliability standards

Access

Introducing a generator reliability standard is intended to increase certainty for generators by defining a level of access for generators to the transmission network that TNSPs are mandated to provide. The level of the standard would be common within geographic zones and would be determined economically.

Introducing a standard should improve access certainty compared to the status quo, although generators would not be able to choose their level of access. The economic analysis that underpins the standard would reflect the value that generators place on certainty. The standard would also be transparent so that generators would have a specified level of access under a set of demand and transmission conditions. However, the "one size fits all" approach is unlikely to lead to a standard that is appropriate for all generation types and there would be a number of implementation issues to address, such as how to value access certainty and how to set the boundary of the zones.

Unlike the access models proposed in packages 4 and 5, this approach would not provide generators with a property right that guarantees access. Nor would generators be able to choose or negotiate the level of access they receive.

No compensation would be payable to generators for whom access fell below the standard. Enforcement of the standards would be through financial incentives attached to the regulatory revenue setting process for TNSPs.

Charging

A generator transmission use of system charge is an integral part of this package. As the new standards ensure a defined level of access for generators, the need for a clear locational price signal to generators is increased. Without such a signal, generators could locate in remote parts of the network with some assurance that they would receive a minimum standard of transmission service, yet the increased transmission costs from such a decision would be met by consumers.

The package proposes that the charge would be introduced for all generators to reflect the relative costs to TNSPs of maintaining the standard and the cost differences of doing so at different points on the network. Further work on the most appropriate apportionment of TNSP revenue requirements between generators and load would be required.

Planning

TNSPs would be required to plan their networks in order to meet and maintain the new generator reliability standard, together with the existing load reliability standards. Where planning studies indicate that generator or load reliability standards would not be achieved, the TNSP would identify and assess potential investment projects that would restore the required level of access for demand or supply accordingly.

The package proposes a hybrid planning standard that is economically derived but expressed deterministically. This seeks to align the arrangements for transmission services for generation with those that are recommended to apply to load. An institution would need to be selected to set the generator reliability standard, a task that would include undertaking the economic analysis that underpins the standard.

8.3 Advantages and disadvantages

This package has the potential, if implemented successfully, to send clearer signals to generators making decisions about where to locate, as well as giving generators greater transparency and certainty about their ability to export their product. This has the potential to reduce investment cost and risk.

Implementing this package would require addressing some challenges including settling methodologies for deriving appropriate standards, setting zone boundaries and calculating generator use of system charges. These issues are considered further in the first interim report. Depending on the level of the standard, this approach may also drive increased transmission expenditure.

9 Package 4: Regional optional firm access model

9.1 Introduction

The fourth proposed policy package would establish a framework to allow generators to elect to pay for firm access for part or all of their output. If transmission constraints prevent dispatch of the firm output, when it would otherwise be dispatched by AEMO, the generator would be eligible for financial compensation.

Transmission planners would need to account for the level of firm access but would make no planning allowance for non-firm generation capacity. Depending on the detail of the model, either new firm generators, or all generation electing for firm access would pay for use of the transmission system. Compensation would be funded by non-firm generation that is dispatched ahead of firm generation when a transmission constraint bound.

9.2 Key features of the regional optional firm access model

Access

This model would provide firm access to generators who are prepared to pay the associated charge. That is, when "in merit" they would be either assured of dispatch or would receive compensation for not being dispatched if congestion prevented this.

Although the model is based on concepts contemplated under the existing rules, it would still represent a substantial change to the current NEM arrangements. It has been developed to reflect the apparent intent of the current provisions of clause 5.4A of the rules, which as noted in 6.2 above, are not currently workable in practice.

This model would allow generators that opted for firm access to manage the risks associated with being constrained off the network. When a generator is constrained off it loses out on the spot market revenue it would have received but for the constraint. It would, however, make savings on short run operating costs such as fuel, compared with the costs it would have incurred had it been dispatched at the prevailing regional price. This model is intended to compensate constrained off generators for this opportunity cost so that the generator is effectively financially indifferent to being constrained off.

Firm access rights would be assigned by TNSPs following generators' applications for those rights. There would need to be a generation planning standard for transmission to assess the necessary transmission capacity to provide for the requested firm access rights. In other words, transmission businesses would have a standard to build to, over time, to meet the required level of firm access in addition to existing load standards. However, the transmission network would not be planned to accommodate non-firm generation.

Charging and compensation

Firm generators could be charged for their access under one of two models. The first is a deep connection charge for new or non-firm generation that wishes to be firm. The transmission charge would reflect the costs of upgrading the transmission system to provide firm access to the relevant standard. There are some challenges with this approach. It would discriminate between new entrants and incumbents, especially if the existing transmission capacity had been grandfathered to existing generators. It is also difficult to establish both the impact that a new generator would have on the transmission system capacity, and to invest in small increments of capacity, given the "lumpy" nature of transmission building.

The alternative option would be a use of system charge paid by all firm generators which reflected, broadly, the costs of providing the quantity of generation output that they wish to be firm. This removes the potential problem with new generators paying a charge that their incumbent competitors may not.

Non-firm generators would not be required to pay either a deep connection charge or ongoing use of system charge. However, they would be required to pay compensation when they are dispatched ahead of a firm generator that would have otherwise been dispatched by AEMO but for a system constraint. This level of compensation is limited such that the non-firm generator would receive at least the offer price.

Conceptually, when congestion occurs, the non-firm generator would pay compensation equal to the difference between the regional reference price and the "locational marginal price" at its connection point. The regional reference price reflects the price of the final unit of generation dispatched at the regional reference node, taking account of congestion. The locational marginal price for a generator islanded by a constraint would be the price of the marginal unit of generation at its location or transmission node.

Provided non-firm generators offer their generation at a level that at least reflects their costs they should benefit financially from being dispatched. It is possible that compensation available and compensation due may not match, in which case scaling of compensation payable may be required.

For more detail readers should consult the first interim report and supporting appendices for a numerical example of the operation of this mechanism.

Planning

As noted above, under this package TNSPs would be required to plan to a generation planning standard that ensured that, under defined operating conditions and ignoring all non-firm generation, all firm generators would be able to access the regional reference node. The Regulatory Investment Test for Transmission would need to be adapted to reflect the new planning standards and would be focussed on ensuring that load and firm generator access standards were met at least cost.

As with the policy package 3, an institution would be required to set the new transmission standard and TNSPs would be subject to financial incentives through the revenue regulation process to maintain the standard.

9.3 Advantages and disadvantages

This approach would allow generators to decide whether the provision of firm access is economic for them or not. This would move some of the responsibility for assessing the benefits of transmission augmentations to those that would be required to pay for those benefits. Increased efficiency, certainty and transparency are likely.

Generators would also be subject to much clearer signals of the cost of the provision of transmission capacity at different locations.

This package has the potential to also address the "disorderly bidding" problem currently associated with transmission congestion. Non-firm generators would not have an incentive to offer their capacity below costs as there is a chance they would be settled at or very close to their offer price. Similarly, firm generators would have an incentive to bid at cost-reflective prices.

Introducing a package of this type would not require significant institutional changes, although it would significantly change responsibilities and incentives. Refining the model and resolving complex issues such as developing new transmission standards and establishing a charging methodology would be a significant task.

10 Package 5: National locational marginal pricing

10.1 Introduction

The fifth and final integrated policy package proposed in the first interim report is a form of generator locational marginal pricing. This would be the most significant departure from current NEM arrangements and draws from, but adapts, experience in other international energy markets. Under this model generators would purchase firm transmission rights at auction from a single, NEM wide transmission business.

10.2 Key features of the national locational marginal pricing model

Access

Under this model it is proposed that the access rights available to generators would provide fully firm rights to access a notional, single, national trading hub. This would remove the concept of regions from the NEM.

Load would be settled at a single "system marginal price" which was set without regard to transmission constraints. Generators would be paid for their output at the locational marginal price applying at their local node. The access right which they could purchase would entitle them to a revenue stream equal to the difference between their local price and the single system marginal price.

This approach would provide all generators with potential access to a national trading hub where all energy would be traded on the same basis, potentially encouraging greater liquidity in energy contract trading than is currently the case.

This model would allow generators to be firm or non-firm, or to be firm for part of their capacity. The access rights would be allocated by an auction of the available transmission capacity consistent with assumptions used in the planning process.

The TNSP would then be obliged to ensure that generators obtained access to the network for which they purchased rights or else pay financial compensation. The TNSP would therefore be exposed to some risk because of this obligation to compensate generators that were unable to access the market in all but extreme circumstances.

Charging

Under this approach all generators, firm and non-firm, would be exposed to a locational signal that reflected transmission capacity and cost. Non-firm generators would be settled at their locational marginal price. Firm generators would see a locational signal through the price paid at auction of firm access rights.

Compensation for firm generators would be funded by revenues that would arise because a non-firm generator is settled at a local price but its output is paid for by load at the system marginal price. If these revenues were insufficient there would be a need for an uplift charge, which would be levied largely on load, although the TNSP would be required to fund part of this as an incentive to minimise compensation payments.

Planning

While this model could be implemented with existing (multiple) TNSPs, it would be more consistent with the model's underlying principles to introduce a single, NEM-wide TNSP. Because generator access is provided across the whole network, a single TNSP would allow for these rights to be provided most efficiently and for incentives to be put in place to drive this. A single TNSP would also have other benefits, including eliminating the need to coordinate planning between TNSPs and promoting consistency of approach across the NEM in matters such as the connection of transmission users.

Planning standards would define the available generator access for which rights could be auctioned and would define the investment needed for release of additional capacity.

There would be a reduced role for the Regulatory Investment Test for Transmission under this framework. It would still be used to identify network investments consistent with maintaining load and additional generator access planning standards at least cost. However, generators would signal the need for, and fund, upgrades to provide market benefits rather than them being assessed by TNSPs in the planning process. In addition, by removing regional boundaries the distinction between inter-regional investment and intra-regional investment would no longer be relevant.

10.3 Advantages and disadvantages

This package has been developed with very limited regard to existing NEM arrangements with a view to considering what may be the most theoretically efficient structure for transmission planning, investment, charging and utilisation. It allocates as much economic decision making as possible with the entities that bear the consequences of those decisions and has the potential to maximise the efficient use of the transmission system because the availability and price of spare capacity will be clearly signalled.

Such a fundamental change to the existing NEM would clearly come with risk and significant costs. These costs would include requirements for changed and additional systems, and the introduction of complex methodologies, particularly in relation to the auctioning of rights. In particular, it is not clear whether the option of a single TNSP is feasible. Introducing the model with multiple TNSPs, while possible, would further increase the complexity of the required regulatory arrangements, if efficient outcomes were to be promoted.

11 Planning

11.1 Introduction

Chapter 11 of the first interim report sets out for consultation a series of options for potentially enhancing or reforming existing transmission network planning and institutional arrangements. The Commission considers that current arrangements are delivering many of the outcomes that would be expected under a well-functioning transmission planning regime. However, we note stakeholders' views that there are some concerns, particularly with regards to the transparency of the investment process and the level of inter-regional investment.

The Commission is also mindful that effective planning and institutional arrangements would be particularly critical under policy packages 1 and 2. Without market signals to inform transmission network planning and investment decisions, greater reliance would be placed on regulatory mechanisms to ensure that TNSPs make efficient decisions. It is in this context that we are considering whether improvements can be made to the current arrangements.

11.2 Potential enhancements to current arrangements

Given that the current arrangements are themselves the product of a number of recent reforms, and the Commission's view that they are generally performing well, we consider that any significant reform to these would require material benefits in order to be warranted. However, we have identified a number of less substantial changes that could be made to enhance the efficiency of the current regime. We are seeking stakeholders' views on these possible measures, which are as follows:

- **Implement the national framework for transmission reliability standards for load** previously proposed by the Commission in its Transmission Reliability Standards Review. The MCE has yet to respond to this recommendation.

- **Improve the consistency of TNSPs' Annual Planning Reports**, such that these reports can more easily be compared to each other and to AEMO's National Transmission Network Development Plan.

- **Improve the transparency of the Regulatory Investment Test for Transmission** so that TNSPs identify the economic impacts of proposed investments on market participants and customers.

- **Align the revenue resets of TNSPs** to improve the coordination and assessment of transmission investment proposals that have inter-regional impacts.

- **Introduce reliability standards for interconnectors** to ensure that interconnector capability is not degraded over time by other developments on transmission networks.

11.3 Options for more significant reform

A number of more substantial options for reform have also been identified based on stakeholder submissions to the review. These include a proposal from the Victorian Department of Primary Industries (Victorian DPI) for a single body to be responsible for transmission planning and procurement across the NEM, similar to the current Victorian regime, and another option that reflects countervailing views that the existing Victorian arrangements might be inappropriate.

The four options are briefly summarised below. Of these, options 1 and 2 are potentially complementary. Options 3 and 4 are mutually exclusive, both in relation to each other and to options 1 and 2.

Option 1: Enhanced coordination of the National Transmission Network Development Plan and the Annual Planning Reports

Under this option AEMO would be required to endorse the TNSPs' Annual Planning Reports and TNSPs would be required to endorse AEMO's National Transmission Network Development Plan. This would aim to improve the coordination of planning while retaining the potential benefits of having a number of different perspectives provided as inputs into the planning process. It would be necessary to develop a process to be followed in the event that AEMO and the various TNSPs could not agree on a consistent approach.

Option 2: Harmonised regime based on current South Australian arrangements

This option would introduce a single set of transmission planning arrangements across all jurisdictions. These arrangements would seek to represent best practice in transmission planning. This option would remove the transaction costs associated with multiple sets of arrangements in the NEM. It would also provide for consistency in the relationships between jurisdictional planners and AEMO as the National Transmission Planner.

In chapter 11 of the first interim report, the Commission notes its view that financial incentives are likely to provide the most robust and transparent driver for efficient decision making. This implies that, in a harmonised regime, transmission investment decisions should not be made by, a not for profit body, as they currently are in Victoria. Instead, this option contemplates the existing South Australian arrangements as forming the basis of a harmonised regime. Investment decisions would be made by for profit TNSPs. AEMO would have a significant role as National Transmission Planner and in providing demand forecasts for use by TNSPs. This would address stakeholder concerns that TNSPs might have an incentive to overstate demand and over-invest.

Option 3: A single NEM-wide transmission planner and procurer

The Victorian DPI has submitted a proposal to the review that seeks to extend AEMO's Victorian planning and procurement role on a national basis. Under this option AEMO would: perform all transmission network planning across the NEM as a not for profit body; procure transmission services through a competitive tender process; and apply the probabilistic planning methodology currently used in Victoria to assess the need for new investment.

The Victorian DPI considers that this approach would have efficiency benefits compared to the existing approach of multiple, regional planners subject to financial incentives. The Commission does not believe that a compelling case has yet been made, however we believe it is appropriate to consult on this option and seek other stakeholders' views.

Option 4: Joint-venture planning body established by TNSPs

As described in chapter 10, policy package 5 contemplates a single national TNSP; this option 4 recognises that a potentially more pragmatic alternative might be for existing TNSPs to establish a joint-venture body. This entity would assume all the rights and obligations associated with being a TNSP across the NEM, although the physical ownership of the networks themselves would be retained by individual TNSPs.

The joint-venture body would have full responsibility for national planning and making investment decisions. It would then direct individual TNSPs to make the required augmentations. This model would employ financial incentives to promote efficient investment decisions, and would aim to give the joint-venture body access to its members' local knowledge and expertise while also being able to take a coordinated approach. However, the role of the AER in assessing the joint-venture's capital expenditure forecasts would be crucial.

12 Issues related to current connection arrangements

12.1 Introduction

From the commencement of this review, generator stakeholders have indicated a significant level of concern with current connection arrangements. Chapters 12, 13, and 14 of the first interim report consider aspects of the frameworks for connecting new generation to the transmission network.

Chapter 12 of the report sets out some of the requirements to connect together with the existing arrangements for connections as set out in the rules. Stakeholders have commented that the existing provisions are in parts unclear, conflicting and that they are inconsistently applied across jurisdictions.

12.2 Connection to the national grid

To connect to the national grid requires a TNSP to provide several different types of services. These may include:

- the provision of a physical connection and in most cases the construction operation and maintenance of assets required to make the physical connection;
- the construction, operation and maintenance of a new substation to allow connection and possibly upgrades to the shared transmission system; and/or
- the construction operation and maintenance of an extension from the generator's facilities to the TNSP's assets that provide the connection.

The treatment of these different types of services lacks clarity in the rules. Ambiguity traverses what is included in each type of service as defined in rules, which part of each service the TNSP is obliged to provide and which parts may be provided by other parties. This ambiguity results in a requirement for a degree of interpretation which has led to variation between TNSPs. Consequently negotiations between generators and TNSPs have been made more complex and so less efficient.

Chapter 12 of the first interim report sets out a number of the key rules concepts and definitions with a view to developing recommendations to resolve ambiguity. Two of the most important of these are:

- *connection services*, which are defined in the rules but this definition does not make clear what the service involves. In practice, connection services do not comprise all the services required to connect a generator to the network; and
- *shared transmission services*, which may include provision of services to connect a generator, for instance through a new substation, but this is not explicit in the rules.

Given the ambiguity associated with these terms, the services required to effect a connection have been defined in the first interim report as "connection-related services".

12.3 Distinction between assets and services

There is also uncertainty whether provision of the services mentioned above by a TNSP necessarily includes provision of the underlying assets that are required to provide the services. This has significant implications for the obligations that TNSPs may have for the construction of the relevant assets. This issue is discussed more in chapters 12 and 13 of the first interim report.

Categories of services for economic regulation purposes

The rules also provide categories of services for the purposes of defining the level of economic regulation applied to services:

- *Prescribed transmission services* – the revenue that a TNSP can generate from the provision of these services is regulated by the AER.
- *Negotiated transmission services* – the charges for these services are not directly regulated by the AER, rather the charge is negotiated between a TNSP and a connecting party under a higher level rule framework with recourse to arbitration a possibility;
- *Non-regulated services* – TNSPs do not have any obligation to provide non-regulated services and the charges are negotiated outside the rules frameworks.

The allocation of services to these categories and so the way in which services are economically regulated is currently unclear, resulting in uncertainty. In practice, many TNSPs use contestability as a means to decide which services are defined as non-regulated transmission services. However, this does not currently have any basis in the rules, which simply defines non-regulated transmission services as those services provided by a TNSP that do not fall within the other two categories.

Amendment required

The uncertainty in the rules about the provision of services required for a connection and the rights and obligations of connecting parties and TNSPs has been amply demonstrated to the Commission.

The Commission considers that amendments to the relevant sections of the rules are required to clarify their interpretation and application. It notes that this clarification should proceed regardless of whether some of the more significant potential reforms relevant to connections that are discussed in chapters 13 and 14 of the report are progressed.

13 Economic regulation of connection-related services

13.1 Introduction

Chapter 13 of the first interim report considers the economic regulation of connection-related services in light of significant stakeholder concern expressed throughout the review. These concerns are particularly focussed on the imbalance in bargaining power that connecting parties face when negotiating with a TNSP for the provision of transmission services.

13.2 Guiding economic principles for the development of options

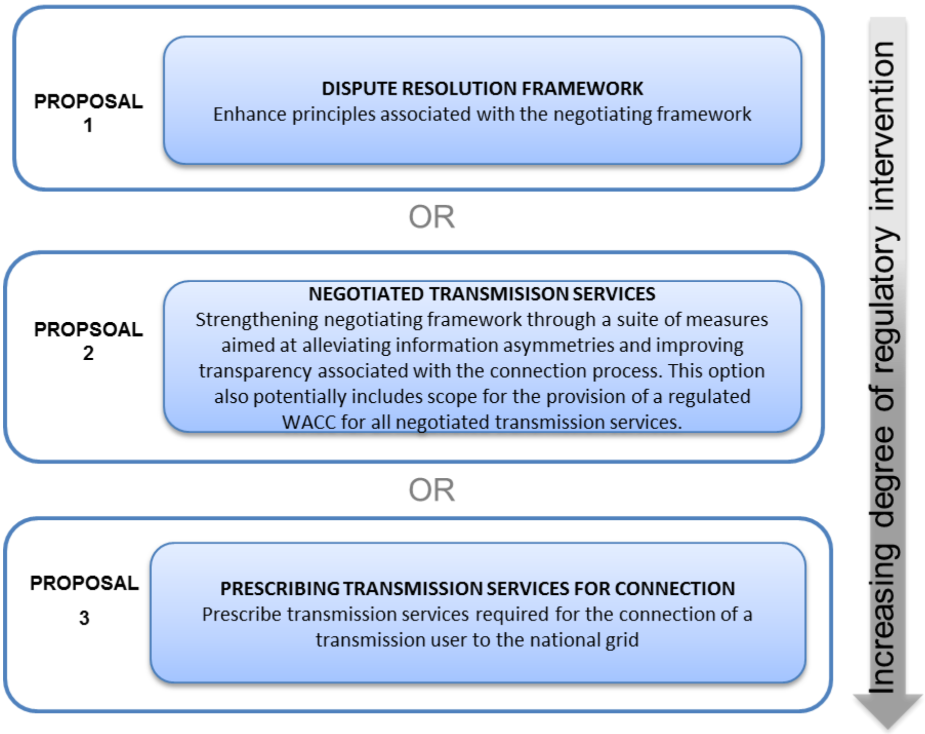
Chapter 13 discusses guiding principles for the economic regulation of connection-related services formulated by the Expert Panel on Energy Access Pricing in 2006. The Commission has used this framework in developing the proposals set out in the chapter.

A key factor in deciding whether change to the current economic regulation of connection-related services is warranted is the materiality of any impacts of the market power that TNSPs hold in negotiating with connection applicants. The relevant factors to be taken into consideration for assessing the extent of market power involved in the supply of transmission services, and therefore an appropriate regulatory framework, include barriers to entry, network externalities, countervailing market power, substitution possibilities and information asymmetry.

13.3 High level outline of proposals

The Commission has developed three proposals for potentially amending the economic regulation of these services. They reflect a range of views about the extent of the imbalance in bargaining power when generators and other transmission users negotiate with a TNSP for connection-related services. These are shown in Figure 13.1 and are discussed briefly below. Further detail is provided in chapter 13 of the first interim report.

Figure 13.1 Proposals for the economic regulation of connection-related services



The Commission notes that it is seeking evidence about the materiality of any impacts the imbalance of bargaining power has on costs and efficiency in order to better assess which of these options are proportionate to the problem.

13.4 Proposal 1: Enhancements to dispute resolution

This proposal establishes an independent arbitrator, potentially the AER, to resolve disputes and changing the arrangements for cost recovery of the disputes resolution process.

The proposal is intended to reduce barriers to arbitration by providing a clear process for dispute resolution and building expertise within the arbitrator. This would promote predictable and consistent decision-making. Potential barriers could be reduced further by amending the arrangements for recovering the costs of arbitration. However, this might increase costs to consumers if recovered from market participants more generally, or increase costs to taxpayers if the additional dispute resolution workload is placed on the AER.

13.5 Proposal 2: Enhancements to the negotiating framework

This proposal involves strengthening the negotiation framework through a suite of complementary measures, potentially including the requirement for TNSPs to:

- provide the connecting party a full breakdown of services and costs associated with the connection;

- provide the connecting party evidence of costs and any changes in costs;
- publish standard contract templates;
- publish a range of indicative or average connection costs; and/or
- provide greater specification of the weighted average cost of capital that is to apply to all negotiated services.

This proposal alleviates some existing information asymmetries while allowing some flexibility to negotiate innovative connection outcomes. This should support commercially efficient outcomes and provide confidence to connecting parties that the prices charged by TNSPs are cost-reflective. However, the disadvantage for connecting parties is the regulatory risk that the weighted average cost of capital (the return that TNSPs can earn on the assets) will change at each TNSP revenue reset. There are also increased risks and administrative costs that this proposal would place on TNSPs.

13.6 Proposal 3: Prescribing transmission services

This proposal represents the greatest change to the current arrangements, which may be considered appropriate if it is concluded that connecting parties have very little effective bargaining power, resulting in materially inefficient outcomes. All connection-related services would be migrated from the category of negotiated transmission services to prescribed transmission services. Under this proposal, the assets used to provide these services would be rolled into the regulatory asset base of a TNSP and charges would be allocated to the connecting party.

This proposal has the advantage of alleviating any imbalances in bargaining power between TNSPs and generators or other transmission users as it would reduce the need for connecting parties to be able to negotiate effectively with TNSPs. It would also provide a strong incentive for TNSPs to minimise costs of connections as the additional revenue to be recovered would be set in a prescriptive manner such that any savings made by the TNSP could be retained by it.

However, generators and other transmission users would face some degree of risk due to charges changing between regulatory control periods. Additionally, without further consideration of prudential arrangements, consumers might also face higher costs due to TNSPs being able to include all new assets in its regulatory asset base and not be reliant on payments from individual generators or transmission users to recover those costs. The TNSP's incentive to minimise connection asset costs might also reduce the scope for flexible or innovative solutions that best meet the needs of connecting parties.

14 Providing and accessing extensions to the shared network

14.1 Introduction

As discussed above, there is considerable uncertainty in the rules regarding how services that are required for a connection are regulated and what TNSPs' and connecting parties' rights are in relation to those services. Chapter 14 of the first interim report considers these issues in the context of the provision of extensions that are required to establish a connection to the national grid.

14.2 Contestability in providing extension services

Currently, TNSPs in most jurisdictions generally treat extensions as a non-regulated transmission service on the basis that extensions are contestable. Such TNSPs consider that there is no reason why TNSPs should have an obligation to provide a contestable service or that such services should be subject to any form of economic regulation. Some stakeholders, particularly generators, disagree with this view and have raised concerns that there is a lack of clarity in this area.

The Commission notes that there may be some barriers to genuine contestability in the provision of extensions to connect to the network. These include:

- any requirement to be a registered TNSP in order to own operate and control the extension;
- any state-based licensing requirements to operate part of a transmission network; and
- the desirability of possessing land acquisition powers to obtain the necessary easements for the land over which the extension will be constructed.

These potential regulatory barriers relate primarily to who may own, operate and control an extension. In contrast, there do not appear to be such barriers to competition in the construction of extensions. Chapter 14 of the first interim report therefore focuses on which entities should be able to own, operate and control extensions, given the factors listed above.

14.3 Ownership, operation and control of extensions

In theory, there are a number of entities who may be able to own, operate and control an extension from a network to a generator's facility. These include:

- the "incumbent" TNSP to whose network the extension is connected;
- any registered TNSP;

- any third party infrastructure owner; and/or
- the connecting party.

There are a number of implications of allowing each of these entities to own, operate and control extensions, particularly in respect of the economic regulation of the service and the third party access provisions that apply.

There may be some benefits to limiting ownership, operation and control of extensions to incumbent TNSPs. For example, it would give them greater flexibility in planning and expanding their networks. However, this would imply a greater degree of regulatory intervention and a loss of competition.

Allowing for competition, whether limited to a registered TNSP or extended to any entity, would reduce the need for economic regulation. However, unless the owner was a registered TNSP then the third party access provisions would not apply (as discussed below). Further, generators that own, operate and control extensions may have an incentive to prevent competitors from accessing an extension.

14.4 Third party access to extensions

The issue of which entities should be able to own, operate and control extensions is directly linked to the question of what rights users have over such extensions.

Currently, the third party access rights that apply to extensions are unclear. Non-regulated transmissions services clearly sit outside the framework for economic regulation of services under the rules, however it is not clear whether they also sit outside the third party access provisions. Therefore it is not clear what rights a new entrant generator or load customer has to connect to an existing extension.

One reason for limiting the contestability of providing extensions to registered TNSPs would be to ensure that the existing access provisions within the rules apply.

Alternatively, if it was considered that third parties should not have a blanket right to connect to extensions that are paid for by other network customers, unlike the shared network, then it may be appropriate to allow any entity to own, operate and control extensions. In this instance, a new entrant may be able to seek access through alternative means, including declaration under Part IIIA of the *Competition and Consumer Act 2010* (Cth) or through that Act's anti-competitive provisions.

Abbreviations

AEMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
MW	megawatts
NEM	National Electricity Market
NEO	National Electricity Objective
NSW	New South Wales
SACP	Shared Access Congestion Pricing
TNSP	Transmission Network Service Provider
Victorian DPI	Victorian Department of Primary Industries