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Network Planning and Connection Arrangements - National Frameworks for Distribution Networks


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1. Introduction

The Allen Consulting Group and NERA Economic Consulting have been asked by the Ministerial Council on Energy’s (MCE) Energy Market Reform Working Group to review and make recommendations on the development of national frameworks for electricity distribution:

- network planning and expansions/extensions;
- network connection arrangements; and
- connection charges and capital works contributions.

The current frameworks for both network planning and network connection arrangements contained in the National Electricity Rules (NER) apply to both transmission and distribution networks. For the purpose of this review, we have limited our consideration of network planning and connection arrangements to distribution networks.

Our review takes as its starting point the existing jurisdictional arrangements as well as provisions currently contained in Chapter 5 and the MCE’s exposure draft of the distribution and pricing rules (herein referred to as ‘Draft’ rules). The scope of our review also includes an assessment of the implications of the proposed frameworks for distributed generation and demand-side response and gives further consideration to:

- the Draft Code of Practice for Embedded Generation (CoPEG) developed by the Utility Regulators’ Forum; and
- the demand side response and distributor generator case studies developed in NERA’s and the ACG’s report entitled “Demand Side Response and Distributed Generation Case Studies”.

Finally, we were also asked to consider the treatment of network losses in distribution networks.

The review of the existing frameworks highlighted a number of areas which we considered to be inconsistent with the promotion of the National Electricity Market (NEM) objective, as provided in section 7 of the National Electricity Law (NEL). Accordingly, we have focused on developing frameworks that seek to promote the NEM objective through simplifying the arrangements, and improving their overall clarity.

The remainder of this report outlines the analysis undertaken in each of these areas and is structured as follows:

- Chapter 2 outlines the proposed approach to planning and network expansions;

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1 Note for the purpose of this paper, distributed generation is used to refer to all generation connected directly to the distribution network. This may include for example, embedded generation, distributed generation and small-scale customer generation such as PV cells. The exception to this referencing approach is where the report refers directly to elements of the existing rules which make use of the defined term embedded generation.
Chapter 3 examines the need to develop a national framework for connection applications, and in particular the need to provide flexibility in the arrangements for different customer types seeking connection;

Chapter 4 analyses and develops a national framework for connection charges;

Chapter 5 examines the treatment of network losses in distribution networks;

Appendices A-G provide an overview of the current jurisdictional arrangements as they relate to network planning, connection applications, connection charges;

Appendix H provides examples of network planning provisions; and

Appendix I contains a summary of the recommendations made throughout this document.

In Chapters 3-6 consideration has also been given to the implications arising from the proposed frameworks for distributed generation and demand-side response and, where relevant, has given consideration to the draft CoPEG and the case studies developed by NERA. The implications of the proposals on the case studies are set out in a revised version of the Demand Side Response and Distributed Generation Case Studies which is attached to this report.
2. **A national framework for network development and planning arrangements**

2.1. **Introduction**

The purpose of this chapter is to provide advice on the development of a national framework for electricity distribution network development and planning. It sets out:

- the purpose of network development and planning arrangements;
- measures contemplated as part of the arrangements;
- the principles and constraints that should inform the design of these measures;
- a summary of current jurisdictional arrangements;
- the proposed network development framework, taking into account the best practice elements and issues that arise from the current jurisdictional arrangements;
- proposed links with Chapter 6 of the National Electricity Rules (Rules);
- an assessment of the consistency of the proposed framework with the National Electricity Law objective; and
- identification of implications and transitional issues.

2.1.1. **Purpose of network development and planning arrangements**

The reason for placing obligations about network planning and development on electricity distribution network service providers (‘DNSPs’ or ‘distributors’) is to address concerns that, in their absence, inefficient network investment may result. The problem stems from the fact that there are insufficient financial incentives on DNSPs under the current approaches to economic regulation to provide sufficient confidence that DNSPs will develop their networks in an optimal manner. There is a related concern that the DNSPs have insufficient incentive to provide sufficient public information about possible non-network opportunities, nor consider non-network solutions when planning network augmentations. Network planning and development requirements therefore seek to provide a direct requirement for DNSPs to provide planning information, and apply sound economic benefit criteria to proposed investments, improving the likelihood of efficient investment occurring.

The promotion of efficient investment in electricity services is one of the requirements of the objective of the National Electricity Law. It is also noted that the intended outcome of the efficient investment in – together with the efficient use of – electricity services is to serve the long term interests of consumers with respect to the price, reliability and security of supply. The promotion of efficient investment by distributors is consistent with this outcome, including by:

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2 The reference to the ‘current approaches to economic regulation’ refers to the incentive arrangements for DNSPs that are applied as part of the setting and review of their regulated charges, which are the result of setting prices (or a price control) for a preset period of time, permitting a carry-over of gains made in the previous regulatory period, and the approach for forecasting expenditure for the period ahead. The AER will be responsible for these decisions in the future, governed by the requirements of Chapter 6 of the National Electricity Rules.
encouraging the cost (and hence price) of providing distribution services to be minimised, for a given level of reliability and security of supply; and

- encouraging an appropriate trade-off of the costs of providing different levels of reliability and security of supply against the benefits to consumers of reliability and security.

Efficient investment is normally described in terms of productive, allocative and dynamic efficiency. The majority of distribution network augmentations are undertaken to improve the reliability of supply to final customers, reflecting that the typical role of distribution networks is to take electricity from a bulk supply point and distribute it to final customers. In this context, allocative efficiency is usually promoted by setting prices that signal the costs caused by a customer’s network usage (in turn, to encourage society to allocate resources to their highest-value use at each point in time), which is guided by the revenue and pricing rules in Chapter 6 of the Rules.

Network development and planning arrangements can contribute to promoting productive efficiency (least-cost production of a given set of goods and services) and dynamic efficiency (optimal resource allocation over time) where the DNSP’s incentives are not aligned closely with the promotion of efficient investment. By way of example, a DNSP may over- or under-invest in reliability investments (i.e. not optimising the trade-off between the value of unserved energy and cost) or over- or under-invest in renewal investments (i.e. for a given level of reliability, not optimising the trade-off between ongoing maintenance and replacement) compared to an efficient level of investment, if it does not have appropriate incentives. A continuing failure to achieve static efficiency over time arising from inappropriate financial incentives could also be said to compromise dynamic efficiency.

Another consequence of the presence of imperfect incentives is that the DNSPs may not naturally seek demand side responses (DSR) and/or network support services provided by distributed generation (DG) as an alternative to undertaking network augmentations, even where it would be efficient for one of them to do so (see 2.1.2.1 below). Administrative measures, therefore, have an important role to address the shortcomings in the incentive arrangements – at least for the time that those shortcomings remain.

The more specific outcomes intended by network development and planning arrangements include the following:

- **Objective 1:** To ensure DNSPs develop the network efficiently in the face of low-powered private incentives to do so. As noted above, efficient investment is a key requirement of the National Electricity Law objective, and is consistent with serving the long term interests of consumers, as intended by the efficiency objective.

  A subsidiary intention to this overall efficiency of network investment is to address a (perceived) failure by DNSPs to look at non-network alternatives in a neutral manner when making distribution augmentations.

- **Objective 2:** To make it easier for network users to plan where best to connect to the network and provide opportunities to do so.

  Even parties who are not considering non-network alternatives will care where they locate if they are required, or choose, to contribute to dedicated network assets or upstream
augmentations (see section 4.4 of this report). This is of particular relevance to large users and to DG. The need to provide this information emerges from the asymmetry of information between the DNSP and potential customer regarding the future timing and location of network constraints.

Objective 3: To allow for efficient planning by parties that may offer alternatives to network augmentations to address emerging constraints.

To remove a potential bias against non-network solutions, DG and DSR proponents should be provided with the opportunity to plan over a reasonable timeframe so that the provider of the non-network solution is able to be in the position to propose a non-network project at the time when a network constraint would need to be addressed. The need to provide this information emerges from the asymmetry of information between the DNSP and potential DSR/DG providers regarding the future timing and location of network constraints.

The principal means for achieving these objectives is to require the DNSPs to undertake certain processes – namely conducting a robust economic assessment of alternatives – and then being subject to strong information transparency about the analysis performed and decision taken. That said, if permitted by the Rules, it would be possible for a failure to meet a planning requirement to affect future regulated revenues and hence have a financial effect on the distributor. This chapter contemplates the following measures, which would create obligations on DNSPs and opportunities to provide assurance regarding the appropriateness of their investment decisions.

DNSP obligations

- Undertake network planning, demonstrating regard to alternatives.
- Demonstrate the application of a cost-benefit assessment of the proposed options and potential alternatives as part of the former.
- Publish the results of the planning activities periodically.
- Demonstrate cost-benefit outcomes on a per project basis as they emerge, again demonstrating regard to alternatives.

Provide assurance regarding the cost-benefit analysis

- Opportunity for public comment/objection on the cost-benefit analysis performed.
- Means for an independent party (e.g. the AER) to have a role in assessing whether the DNSP has met its planning requirements, which may comprise dispute resolution in the case of objections, or the assessment of the distributor’s compliance with the planning obligations and enforcement of those obligations.

2.1.2. Design principles and constraints

This section sets out the principles and constraints that should inform the design of network planning and development measures. In developing this view we have taken into account the relevant principles from:
Harmonisation of transmission and distribution arrangements

One of the key themes of the recent energy market reforms has been to apply a consistent (or common) approach to regulation across the energy sector, where appropriate. The different regulated sectors compete for investment capital, and consistency will help reduce the risk of regulatory distortions to the flow of capital to the sectors. In addition, consistency of approach across the various levels of the electricity sector – and across the electricity and gas sectors – will reduce the compliance costs of participants in the industries (including retailers), for whom the cost of remaining abreast of regulatory measures and developments is not immaterial. Having said that, it is clear that a consistent regulatory approach will imply a different outcome across the different sectors if there are material differences in the relevant aspects of the market served or technology employed across those sectors.

Turning to planning arrangements and focussing on electricity, those parts of the regulatory framework that deal with aspects in which the two sectors are materially similar should therefore be consistent. In its explanatory material accompanying the exposure draft for Chapter 6 of the Rules (dealing with the economic regulation of distribution), the MCE SCO identifies the following differences between distribution and transmission networks:
Table 2.1: Fundamental differences between distribution and transmission networks

<table>
<thead>
<tr>
<th>Issue</th>
<th>Transmission</th>
<th>Distribution</th>
<th>Implications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Key role in market</td>
<td>Reliability and security of supply. Increased competition and supply/demand balancing between regions. TUOS represents about 8% of average end-user price.</td>
<td>Reliability and security for individual consumers and subregions. DUOS represents between 40-50% of average end-user price.</td>
<td>Transmission can have significant impact on market outcomes. Distribution has little impact on wholesale market. Increased distribution pricing has much higher impact on consumers.</td>
</tr>
<tr>
<td>Impacts of under investment</td>
<td>Less reliable supply and system security. Price separation between regions, distorted economic dispatch within regions and redirected generation investment – efficiency risk.</td>
<td>Blackouts in service areas and poor quality of supply – security risk.</td>
<td>Different stakeholders and political risks for underdevelopment.</td>
</tr>
<tr>
<td>Key customers</td>
<td>Large generators and distribution networks. Generally registered market participants.</td>
<td>Households, small businesses, industrial and commercial customers, local government for streetlights, embedded generators. Generally not registered market participants.</td>
<td>In negotiation, information and commercial power asymmetry tends to be much higher in distribution. Registered market participants can be influenced by provisions elsewhere in the Rules.</td>
</tr>
<tr>
<td>&quot;Lumpiness&quot; of capital assets and investment</td>
<td>Small number of large assets. Investments also governed by Chapter 5 of the NER (including the Regulatory Test).</td>
<td>Large number of smaller assets. Regular investments to facilitate new connections, system augmentation and asset replacement. Chapter 5 provisions (including regulatory test) also apply to investments.</td>
<td></td>
</tr>
</tbody>
</table>


A key difference for the planning arrangements for distribution compared to transmission is the difference in the scale of the projects. Distribution networks have more projects of smaller scale than transmission. Guided by the principle that the costs of imposing any regulatory intervention must not outweigh the benefits (see Expert Panel (2006), pp. 11-2 for a discussion of proportionality and its implications for the design of regulatory instruments) this would suggest a lower cost planning framework to administer and participate in for distribution than for transmission. For example, the cost to proponents of non-network alternatives of providing information in an augmentation assessment must not be so great as to impose a barrier to small projects. Similarly, the cost of administering the process of evaluating projects should be such that it is commensurate with the scale of the projects being considered, and hence deliver a net benefit to the market.

Of particular importance to the planning arrangements, proponents of non-network alternatives to a distribution augmentation are likely to be less informed or able (i.e. within the financial scale of their proposed project) to dispute an evaluation of a distribution project than would be the case for parties who may dispute a transmission project. Accordingly, there are grounds for considering measures to address this potential absence of a disputant, for example by requiring a more active role for a regulator in overseeing and enforcing distribution investment evaluations than is the case for transmission, and to place less
emphasis on relying on a high degree of transparency and stakeholders’ vigilant pursuit of their best interests to ‘enforce’ the regime.

A further implication of the scale of distribution projects relates to the capacity to forecast future investment requirements in the respective sectors. Given that transmission effectively performs the role of bulk transport from sources of generation to major demand centres, its load at any point generally is diversified across a large number of customers. In contrast, distribution needs to generally be more sensitive to the needs to subsets of customers. The sensitivity of distribution to the decisions of smaller groups of customers means that it is more difficult to forecast future specific investments – or future constraints – than it is for transmission. In turn, this aspect of distribution will have implications for the term over which planning – and the related information provision – is to be required.

Another key difference between transmission and distribution is that, although reliability investments account for the bulk of network investments, transmission businesses are more likely to have projects that deliver wider market benefits (for example, by permitting a reduction in generation operating costs, deferring the need for new generation or permitting a lower-cost generation option). Accordingly, the justification for the network business having the option of conducting a less elaborate test of the relative merits of different projects arguably is stronger for distribution than it is for transmission. That said, however, there may be distribution projects that do deliver wider market benefits, and so the capacity for the distributor to undertake a more elaborate analysis of the relative merits of different projects where this would be appropriate should remain.

2.1.2.2. Harmonisation of jurisdictional arrangements into a national regime

As identified in section 2.2, jurisdictional planning arrangements differ significantly. Even where they are similar in their objectives and means, they differ in matters of detail. In addition, the jurisdictional arrangements are achieved through a variety of means – some within the latitude of the Rules, others through jurisdictional legal instruments such as licensing conditions.

The differences in the substantive provisions across jurisdictions bring with them the potential for inefficiency in decisions, for example in the timing and location of generation entry where the generator would connect to a distribution network. More importantly, however, the profusion of regulatory instruments across the jurisdictions – and, in some cases, within a particular jurisdiction – impose a learning cost on market participants that can be a material proportion of the total cost of a project. The significance of this cost for large customers intending a network connection will vary, depending on the size and nature of their projects. For those for whom it is significant, the cost arguably impedes their ability to achieve economies of scale by undertaking their activities across multiple jurisdictions. Moreover, the AER, who would regulate the arrangements, would also benefit from having to enforce the requirements through a common regime applying to all DNSPs, rather than seeking to enforce multiple, different schemes. Thus, harmonisation is also likely to support better compliance with the requirements and therefore underpin the efficiency objectives they are designed to achieve.

For the new arrangements to have their intended effect – namely, to facilitate efficient locational and timing decisions by customers across the national electricity market, while also
minimising the costs that participants incur to determine their optimal location and timing – consistency of the high-level legal obligations on distributors would be insufficient. Rather, commonality of the planning procedures and planning-related information that distributors release is required. This, in turn, argues for the new arrangements to contain a level of detail on what is expected of DNSPs in relation to the material that is published and the processes they undertake.

The new institutional arrangements and legal framework for the energy sector will facilitate the harmonisation of planning arrangements for electricity distribution that are proposed in this report. In particular, it is proposed that the Rules contain the high-level obligations on the DNSPs with respect to planning and the publication of planning-related information, and for these obligations to be supplemented by statements of specific requirements issued by the AER on more detailed matters – including on the form of information disclosure. A key strength of the new institutional and legal framework is that the Rules (and any AER statements of specific requirements issued there under) can be subject to continuous review and changed in a reasonably expeditious manner if, in the light of experience, certain measures are found subsequently to be inappropriate. It is because of this ability to review the regime in the future that this report is more definitive in its recommendations about the requirements for the future planning regime than otherwise may be justified.

Lastly, whilst the discussion above noted our concerns about the profusion and complexity in the current planning arrangements, it is important for the new national regime to build to the extent possible on the regimes that have been put in place in the jurisdictions to date and the lessons that have already been learned. It is acknowledged here that the existing jurisdictional regimes contain elements that are innovative, and welcomed by the target industry participants.

### 2.1.2.3. Particular requirements of non-network alternatives

DSR and DG may, in certain circumstances, both provide efficient solutions to network constraints and be a substitute for network augmentation (that is, if the right combination of customers at specific locations will reduce demand at peak times, or if a generator locates itself within a distribution network, or will do so as a result of incentives). Our review for the Ministerial Council on Energy’s Network Policy Working Group analysed whether the initial rules for the economic regulation of distribution would promote efficient DSR/DG (NERA and ACG, March 2007). One conclusion of this investigation was that it is possible to overcome the technical barriers to efficient pricing – e.g. the lack of interval meters – but even if efficient prices prevailed, DNSPs would continue to have incentives to prefer network to non-network solutions. Of relevance to the network planning and development processes are DNSP incentives:

- generally, to be less vigilant in relation to seeking out the most cost effective solutions to providing the preferred level of service capability at least cost – which may be combined with perceptions that network businesses prefer network solutions for ‘cultural’ reasons or because investment in their own assets may afford greater control;

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3 Note that any specific requirements issued by the AER to comply with the Rules would be subject to the distribution consultation procedures set out in Part H of the draft exposure of Chapter 6 of the National Electricity Rules.
to prefer undertaking capital expenditure in preference to operating expenditure, given
that the power of the incentive regime in relation to capital expenditure is lower than for
operating expenditure for most DNSPs. This is relevant for the choice between network
and non-network solutions as the former are capital expenditure and the latter generally
take the form of operating expenditure; and

- to make expenditure or investment choices that emphasise or reinforce the intrinsic
degree of market power typically possessed by an electricity distributor – which may
encourage a DNSP to seek to ‘foreclose’ entry into the market by a DG in order to
remove competition for the network services.

In our previous report (NERA and ACG, March 2007), we recommended measures to
address some of the incentive problems described above, and in particular, to attempt to
remove any direct financial disincentive against substituting non-network solutions for
network expenditure (i.e. point two above). However, an inevitable consequence of the
incentive regimes – at least as at present – is that even where DNSPs should be neutral
between technologies, the financial rewards for selecting the lowest cost option may not be
strong. Hence, combined with concerns about cultural and other biases, it is difficult to have
confidence that DNSPs naturally will have the incentive to adopt non-network solutions (DG
and DSR) when it would be efficient to do so. Therefore Chapter 5 of the Rules will also be
important in order to put in place an administrative/regulatory framework for planning
requirements and negotiation for connections (see Chapters 3-4 of this report) to address
these remaining problems.

Turning now to the particular needs of DG and DSR, a key requirement for these projects is
that adequate and timely information on emerging network constraints is available. While
there is substantial emphasis in the National Electricity Rules and many jurisdictional
instruments on the need for network businesses to plan ahead over a reasonable timeframe, it
is clear that DG as well as DSR projects also need to be planned in advance of being required.
Accordingly, to be a feasible alternative to network augmentation, investors in DG and DSR
projects need to know of potential network constraints up to five years in advance in order to
plan their response. Prospective DG providers will then be able to identify and site in the best
location by reference to:

- alleviating network constraints (and potentially earning network support payments); or
- maximising energy transfer capability without incurring additional deep connection
costs.\(^4\)

Secondly, the scale of DSR and DG are often (but not always) small and, as noted already
above, distribution investments themselves are typically of much smaller scale than
transmission augmentations. This will require a planning and evaluation framework that
imposes low transaction costs on DSR/DG proponents, and transactions costs on DNSPs that
are commensurate with the scale of the projects being evaluated. It will also require

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\(^4\) The discussion of DG in this chapter relates to its role as a potential non-network alternative to an emerging constraint.
The case of a distributed generator wishing to connect to the network independent of any network support activity, and
the treatment of consequent network augmentations, falls within the network connection and charging framework.
Please see chapters 3-4 of this report for our discussion of these matters and section 4.4.2 in particular for
recommendations on efficient connection charging (including the role of the regulatory test).
planning-related information to be such that it can be understood by non-experts in distribution planning, hence minimising the need for DSR/DG proponents to engage expert advisers, at least in the initial stages of developing potential projects.

### 2.1.2.4. Strategic planning role and the ERIG (2007) report

One of the key issues addressed in the ERIG (2007) report related to the planning framework and institutional arrangements for electricity transmission. ERIG made a number of observations on the actual and perceived effectiveness of the existing transmission planning regime, and made a number of recommendations for change, most notably for this report:

1. **institutional arrangements** – to enhance the role that NEMMCO currently performs in order to improve the degree of national coordination of transmission planning by an entity that is separate to the transmission network service providers (‘TNSPs’ or ‘transmission companies’), with a key role of that organisation being to publish a National Transmission Development Plan. This plan is intended to guide the efficient development of the national transmission network. ERIG noted that a second option would be to take planning and investment decision responsibilities from the TNSPs and allocate these to an independent entity (replicating the arrangements between VENCorp and SP AusNet in Victoria); and

2. **regulatory test** – to merge the two separate ‘limbs’ of the regulatory test into one,\(^5\) in order to remove the perceived incentive for TNSPs to avail themselves of the procedurally simpler reliability limb of the regulatory test at the possible expense of projects that may deliver a greater net market benefit. The application of the test (referred to as the ‘Project Assessment and Consultation Stage’) would be informed by (and take place in the context of) the National Transmission Development Plan.

ERIG’s recommendations for the change to institutional arrangements stemmed in large part from its concern to maximise national coordination in the development of the transmission network, emphasising the importance of flows between jurisdictions and interdependences across the transmission network for the efficient operation of the NEM. It also noted the important effect that transmission investment decisions may have on electricity spot prices, and of the consequent benefit to market participants from a regime that instilled confidence and predictability in those planning decisions. One of its rationales for the enhanced role of the independent planner was to enhance this confidence. In addition, ERIG identified similar concerns about the incentives for transmission companies as those identified above for distributors – namely the low power of the existing incentive arrangements, that TNSPs lack the financial incentive to make efficient decisions from a NEM-wide perspective and the potential for a TNSP to make planning decisions that are weighted against non-network options.

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\(^5\) Where the TNSP faces a mandatory reliability standard, the current regulatory test requires that it select the least cost project that satisfies the relevant standard – this is known as the ‘reliability limb’ of the regulatory test. Where a TNSP wishes to construct a project that produces a range of market benefits (such as a reduction in short and long term generation costs and potentially also reliability) it must estimate these other benefits for the proposed project and possible alternative projects, all estimated for a range of market development scenarios and sensitivities of key inputs – this is known as the ‘market benefits limb’ of the regulatory test. The reliability limb of the regulatory test provides a more straightforward test to evaluate investment options.
While it is noted that the final position on the ERIG recommendations is still in development, some observations on the relevance of ERIG’s views for the planning regime for distributors is in order. An issue of particular relevance is whether adopting an independent planning function for transmission would mean that the same model should be applied to distribution.

We consider that ERIG’s main concern that sat behind its view that there should be independence in transmission planning – namely to improve the degree of national coordination across what is a national market – is of less relevance to the planning of distribution networks than for transmission networks. In particular, the majority of distribution network augmentations are to improve the reliability to final customers, as already noted. Moreover, even in the case of DG – where the DNSP’s role is extended to one that includes the transportation of bulk supply – the scale of most DG projects means that the national market implications of distribution investments are unlikely to be material. For similar reasons, the ‘market confidence’ rationale for independent planning is much less pressing for distribution.

Regarding the third of the arguments – namely the incentives on the businesses – it is our view that the incentive problems for distribution are less marked than for transmission, and hence the degree of reliance that has to be placed on the administrative planning requirements is commensurately less. The very lumpy nature of assets in transmission, combined with the substantial interdependencies across and between transmission networks, makes the design of an incentive arrangement that exposes transmission companies to a share of both the (full) benefits and costs of transmission investments, while not placing the transmission company in a position of excessive risk, very challenging (and maybe impossible). For distribution, however, the benefits of investments are more straightforward to identify (and are incorporated into some of the existing jurisdictional regimes), and we are confident that improved incentives with respect to the cost of projects will be possible over time.

Accordingly, we do not consider that there would be material benefits from extending any changes to the institutional arrangements for transmission planning to distribution. We note, however, that an implication of our recommendations would be that the level of prescription and guidance in the Rules for distribution network planning would increase, hence increasing the level of oversight of this activity in any event. A sufficient degree of prescription would also promote the consistency of DNSPs’ plans between and across jurisdictions. Together with the requirement for all distributor planning materials to be available from a centralised location, this should promote the transparency and comparability of distribution network planning information, with the expected benefits for efficient investment as identified above. Detailed recommendations relating to this point follow in section 2.3.

Turning to the form of the regulatory test, it is noted that the high-level objective – namely, for projects to be subject to an economic cost-benefit test – is not disputed in the ERIG (2007) report. Rather, the matters raised by ERIG relate to how that test is to be made operational and applied in practice. Our view is that if there are amendments to the current specification to the test that are judged to be appropriate for transmission, then we would see no reason that these should not be carried over directly to distribution, except where the technical features of the different sectors warrant a different approach. As discussed further below, a key requirement for distribution is that the level of sophistication of the cost-benefit test that the distributors are required to apply continue to be commensurate with the scale of the relevant project.
Having said that, one of the changes recommended by ERIG for transmission is for the independent planner to undertake and release a National Transmission Development Plan, and it is intended that applications of the regulatory test would be performed in the context of this plan. Amongst other things, the plan would be expected to determine (or assist in determining) the assumptions to be made about developments in other areas of the NEM, and hence assist in determining a full picture of the future market ‘with’ the particular investment compared to ‘without’ that investment. However, given our views about the lack of material interaction between investment in one distribution network and wider market outcomes, we would not see there to be any basis for extending the national plan to include distribution investments.

2.1.2.5. Principles for the design of national planning arrangements for distribution

Drawing together the discussion above, we conclude that the following principles should be the key design features for the new distribution network development and planning arrangements. These principles are given effect by the detailed recommendations for a national distribution network planning and development framework that follow in section 2.3:

- the arrangements should place an effective discipline over the DNSPs’ planning processes and decisions;
- DNSPs should be required to release sufficient information, and information in a sufficiently accessible form, to facilitate efficient planning by other participants (including DG and DSR proponents);
- the arrangements should be cognisant of the typically small scale of distribution projects and users of distribution networks (including DSR/DG proponents);
- the arrangements should be consistent with those that apply to transmission, while taking account of the differences between transmission and distribution (most notably, with respect to scale of the projects and the relative capacities to forecast future constraints and network augmentations);
- the arrangements should be the same nationally, in order to minimise the administrative costs of market participants to the extent possible and provide sufficient direction to the distributors to generate commonality in planning processes undertaken and in the planning-related information that is released;
- the arrangements should be simplified wherever possible and put under the new legal framework, namely by including the specific planning obligations on the DNSPs in the Rules and requiring the AER to issue statements of specific requirements where necessary on the more detailed requirements; and
- there should not be a national coordination or independent network planning role for distribution.
2.2. Current jurisdictional arrangements

The purpose of this section is to provide a summary of the current arrangements for network development and planning under the Rules and state-based regulatory arrangements and legal instruments.\(^6\) By drawing a picture of the broad themes that emerge we are able to select the elements of best practice and identify issues that underlie our recommended process (see section 2.3 below). The detail of the current planning arrangements for transmission and distribution is provided in Appendices A-G.

The National Electricity Rules prescribe the consultation process that a distributor must follow in developing its network in the case of large network assets – i.e. those projects with an estimated capitalised cost greater than $10 million. For distribution assets with an estimated capital cost less than $10 million, distributors do not have to engage in any formal consultation process. However, in relation to the publication of information, the Rules are less definitive in the obligations imposed.

Clause 6.2.3(e)(2) of the Rules, Principles for regulation of distribution pricing, also requires the regulatory regimes established by the jurisdictions to have regard to the need to:

“Create an environment in which energy storage, demand side options and network augmentation are given due and reasonable consideration”

Reflecting this requirement, a number of the states have imposed requirements on distributors to engage in planning processes more detailed than those required under the Chapter 5 provisions, and in the case of proposed network augmentations to consult more widely. The models adopted have some similarities and there appears to have been a certain amount of cross-fertilisation between jurisdictions.

The current network development and planning requirements may be grouped under a framework with the following six elements.

2.2.1. Periodic planning

The Rules require distributors to plan their distribution networks over a five year forward horizon; however, there is no requirement on distributors for publication of the results of the planning exercise with respect to distribution assets.\(^7\)

The transmission Rules require transmission companies to undertake an annual planning review of their network over a 10 year period and publish an Annual Planning Report that sets out prescribed information relating to the results of that review. NEMMCO is also required to prepare and publish an Annual Transmission Statement, which sets out forecast constraints and proposed solutions along the national transmission flow paths. Transmission companies – in conjunction with the relevant distributor(s) – must also assess the adequacy of connection points and identify proposals for future connection points.

\(^6\) Collectively the national rules and state-based arrangements are referred to as ‘jurisdictional arrangements’.

\(^7\) The DNSPs are required to plan jointly with TNSPs for connection assets between the transmission and distribution networks, and to publish the results of this planning exercise. As these are transmission assets, these planning requirements are not addressed in this report.
All jurisdictions, with the exception of ACT, require the completion of an annual network plan identifying emerging constraints on the distribution network over a varying time period. The state regimes all make clear that one of the key purposes of this report is to ensure DSR/DG options are considered as part of network planning. Both South Australia and New South Wales state explicitly that the plan must identify the information needed by customers or interested parties to develop cost effective system support options. Similarly, Victoria, Tasmania and Queensland require the distributor to identify where feasible options for meeting forecast demand through DG or DSR exist. However, the quality of the reports produced under these similar requirements vary significantly in terms of their ease of use, the level of detail and the manner that they are presented.

### 2.2.2. Periodic reporting

While the distribution Rules do not contain a periodic reporting requirement, where the distributor identifies emerging constraints on the basis of load forecasts it must notify NEMMCO and participants of the expected time to allow the appropriate network augmentation, non-network alternatives or modification to connection facilities.

As noted above, the transmission Rules require transmission companies to publish their Annual Planning Reports and NEMMCO to publish the ANTS. Where an emerging constraint is identified, the transmission company must also notify NEMMCO and affected registered participants and advise on the time required for a solution to be implemented.

With the exception of Aurora in Tasmania, all of the distributors publish annual planning reports on their websites. We understand that Aurora intends to publish plans on its website in the future.

In both New South Wales and South Australia the distributor is also required to report annually on performance against these plans, setting out its demand management activities and investigations as well as the network projects that have been completed.

### 2.2.3. Consideration of non-network alternatives

Under the distribution Rules, where the proposed augmentation is greater than $10 million, the distributor is required to consult registered participants, NEMMCO and Interested Parties and to try to identify non-network alternatives. For small distribution network assets (augmentations with an estimated required investment $1-10m) it is not clear from clause 5.6.2(g) whether the distributor must include non-network alternatives in its assessment of possible options to address emerging constraints; there is no requirement on the distributor to undertake consultation.

Under the transmission Rules, the Annual Planning Report (all proposed augmentations) or ‘application notice’ (for large network assets) needs to explain which non-network options a transmission company has considered for all proposed network augmentations:

- In the case of small network assets the annual planning report should include a ranking of the reasonable alternatives in line with the regulatory test principles (5.6.2A(b)(5)).
- In the case of augmentations involving large transmission network assets a transmission company must include all reasonable non-network alternatives as part of the case-by-case
project assessment (5.6.6(c)(1)(iii)) in the application notice, and to satisfy the regulatory test the transmission company must publish a request for information to help identify alternative options (5.6.5A(c)(4)).

As noted, most states require the publication of an annual plan, and those that do refer to its use for signalling the opportunity for non-network solutions. South Australia and New South Wales have both added conditions into distributor licences requiring them to consider explicitly the possibility of demand management and non network solutions to defer network augmentations and have published formal guidance on the process the distributor needs to undertake to comply with this condition.

2.2.4. Case-by case project assessments and consultation

The Rules require distributors to notify registered participants of emerging constraints and to consult on options for remedying if the investment would be over $10 million. These options should include, but not be limited to, demand side options, generation options, and market network service options.

If proposing a new large network transmission asset a transmission company must publish a detailed report (an application notice) and consult all registered participants, NEMMCO and Interested Parties. Submissions in response to the application notice must be made within thirty days, and the transmission company must review these submissions before publishing a final report.

A transmission company must also consult on the proposals for new small transmission assets it describes in the annual planning report. Interested Parties are required to respond within 20 days of the publication of its Annual Planning Report. If any matters change as result of this consultation process the transmission company must republish the relevant part of its report. If a transmission company identifies the need for a new small transmission asset which it had not identified in its annual planning report it must publish and consult on a stand alone report carrying the same details.

Both New South Wales and South Australia require a case-by-case assessment of all proposed augmentations to evaluate the possibility of non-network solutions. In each case this requires an initial ‘reasonableness’ test to filter situations where non-network options have a greater likelihood of being economic, and where this is satisfied the issue of a ‘request for proposal’ (RFP) inviting proposals from demand management proponents. Both states provide detailed instructions on what should be included in an RFP and the process for evaluating the options identified.

2.2.5. Evaluation of options – economic test

The obligations with respect to project evaluations are not consistent across the regimes.

The Rules require distributors to conduct an economic cost effectiveness test and consult on that analysis if the investment would be over $10 million, and a report is required to be published on the economic cost effectiveness test. The term ‘cost effectiveness test’ is used in the Rules to refer to a test whereby the lowest cost option of meeting a reliability obligation is selected.
All small or large augmentations to the transmission network are required to satisfy the regulatory test. The test includes a cost-benefit analysis of the future based on scenarios with or without the new network investment and compared to likely alternative options. The only difference in the test carried out for a large transmission network asset is that the transmission company is required to publish a request for information to identify alternative options (5.6.5A(c)(4)). The test, however, should not require a level of analysis disproportionate to the scale of the investment (5.6.5A(c)(6)).

Only New South Wales and South Australia describe the evaluation process that distributors should follow in considering projects. Both states stipulate that the test should rank all options based on the total annualised cost to the distributor of providing system support plus the net effect on system losses. South Australia also draws an explicit link to the national framework stating that it should also comply with regulatory test.

2.2.6. Regulatory oversight or dispute resolution

The Rules permit a Registered Participant or Interested Party to dispute the distributor’s application of the economic cost effectiveness test if the project is over $10 million or would imply a rise in a particular customer’s bill of more than 2 per cent. The distributor and disputant are required to ‘negotiate in good faith’ to resolve the dispute. The reference to ‘negotiate in good faith’ means that recourse to the dispute resolution section in chapter 8 of the Rules is available; however, that dispute resolution process only extends to disputes between Registered Participants and not to interested parties.

Parties may dispute the contents of the transmission company report on a large transmission network asset. The matters are limited (clause 5.6.6(j)) to:

- possible alternatives and their ranking according to the principles of the regulatory test;
- whether there is a material inter-network impact;
- whether the asset satisfies the regulatory test, and the basis for that assessment, but only if the asset is not a reliability augmentation; and
- whether the asset satisfies the criteria for a reliability augmentation.

The AER is required to make a determination to resolve the dispute, but its powers to do so are limited to the matters that may be disputed under 5.6.6(j).

Where the new large transmission asset is not a reliability augmentation and the findings are not in dispute the transmission company may request the AER to make a determination as to whether it satisfies the regulatory test.

In South Australia an aggrieved party can appeal informally to ETSA Utilities or to the regulator if it disagrees with a distributor's determination. Abiding by the planning requirements set out by the Essential Services Commission of South Australia (‘ESCOSA’) is a mandatory license condition. Failure to do so could potentially be treated as a license breach and be subject to fines of up to $1 million under the Electricity Supply Act 1996, although it is not clear whether this option would ever be pursued in practice.

A similar framework operates in New South Wales where the planning requirements are also
stipulated in the licence. In New South Wales, however, the Department of Energy, Utilities and Sustainability oversees the licence conditions (not an independent regulator) and the distributors are all state-owned companies. IPART has, however, stated that it will review the prudence of investments as part of the roll-forward of the regulatory asset base; it has also stated that it will consider non-network alternatives on the same basis and according to the same principles.\(^8\) The logical conclusion of this is that if it was brought to IPART’s attention that the distributor had clearly not abided by the planning guidelines (for example by rejecting a more efficient non-network solution in favour of a network solution), it runs the risk of not having that investment rolled into the regulatory asset base at the time of its next regulatory determination.\(^9\)

No other states have a formal dispute resolution process for planning disputes. However, as the planning requirements that do exist are requirements that the distributors must adhere to under their licences, the possibility again exists that if they failed to do so this could be treated as a license breach, with relevant penalties applying. Again it is not clear how likely it is that this avenue would be pursued in practice.

### 2.2.7. Findings

A number of broad themes emerge from a comparison of the existing arrangements for transmission and distribution planning arrangements.

While the Rules contain a number of desirable elements for a planning regime, there are a number of shortcomings.

- First, there is no requirement for periodic reporting of planning outcomes.
- Secondly, the obligations on the distributors are specified at a very high-level, which is unlikely to generate a sufficiently consistent approach to information provision and public reporting across the NEM to minimise the learning and other costs to connecting parties (including DG / DSR participants).
- Thirdly, both the process and ‘enforcement’ of the economic test is largely unspecified. For the latter, the use of the Chapter 8 process is likely to be excessively costly and cumbersome for small participants and also appears to exclude many potential DG / DSR proponents (as recourse to the dispute resolution process appears to be limited to Registered Participants).
- Fourthly, the obligations on the distributors to consult in relation to economic assessments of projects and to explain their decisions apply only in relation to very large projects – being those over $10 million, and it is not clear whether this threshold is appropriate.

Indeed, the planning arrangements for transmission differ substantially to those for distribution, the former having been amended several times – and expanded in the process –

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\(^9\) We note, however, that the AER is expected to undertake the next and subsequent price reviews for the NSW distributors, and whether the AER is able to, or decides to, review the prudence of investments in the manner that IPART had foreshadowed will depend upon the future Rules for setting distribution revenues and prices.
since the introduction of the National Electricity Code. In contrast, jurisdictional arrangements effectively have been left to create a more defined planning regime for distribution.

The existing state planning arrangements are predominantly oriented towards encouraging the development of non-network solutions as a means to defer augmentation rather than to encourage efficient investment per se (which we consider inappropriate, as discussed further below). Where the regimes are similar, they vary significantly in the level of detail. Both New South Wales and South Australia have regimes that set out in some detail the requirements or expectations of the distributors in their planning activities. These require not just the publication of an annual plan, but also a formal consultation process on specific geographical constraints and a transparent evaluation of the options that arise. Victoria, Queensland and Tasmania have maintained non-prescriptive regimes.

There are areas where the regimes have diverged significantly. For example, while the Rules are prescriptive on consultation processes for large distribution assets, they explicitly omit a requirement for consultation on small assets (and diverge from the transmission Rules in this regard). The states have responded in a variety of ways to this omission with thresholds for required consultation varying from $200 000 (New South Wales) estimated capital cost to $2 million (South Australia), or by continuing the omission (Victoria, Queensland, Tasmania).

Lastly, the processes that the states have developed are evolving, in particular in South Australia and New South Wales where regulators have recently reviewed the planning arrangements. It is important that a national framework builds on those experiences in order to develop a best practice approach.

2.3. Proposed network development framework

The purpose of this section is to recommend a national framework that incorporates the elements of best practice from the current jurisdictional arrangements and addresses the issues that we have found with those arrangements.

As discussed above, the only national arrangements – the clauses in Chapter 5 of the Rules – alone are too vague to ensure that the planning obligations operate effectively across the NEM and that the planning material produced is sufficiently consistent to minimise costs to connecting parties, including DSR or DG participants.

The state arrangements are an improvement – but are different across the states, with the rigour and transparency of these arrangements clearly more developed in some regimes than in others. Even if the differences are not marked, the existence of multiple regimes raises the costs to industry participants. There is a strong case that a degree of consistency across all the jurisdictions regarding the type of information provided by DNSPs, and the format in which it is presented, would assist all potentially connecting parties to identify prospective opportunities on a national basis. Moreover, within each jurisdiction, the profusion of regulatory instruments also adds to the difficulty of understanding the full arrangements, and hence adds to cost.

We note at the outset that the direct evidence on the success of the jurisdictional arrangements to date is limited. While ESCOSA has placed requirements on ETSA Utilities
to seek out non-network solutions for a number of years – and has accepted that ETSA Utilities has complied with these requirements – a DG or DSR option has not as yet been selected in preference to a network solution. There are a number of factors that could explain this outcome – two competing hypotheses are that ETSA Utilities dismissed non-network options inappropriately, or that the network options were economic in all cases. Our view, however, is that there is a potential for DSR and DG to have a material role in the future, and as such a robust regime for distribution planning should continue to exist. As was noted above, if experience later demonstrates this belief to be in error, then the Rules (and AER statements of specific requirements issued there under) can be modified or removed in an expeditious manner from that time onwards.

As discussed above, a key difference between the planning arrangements for transmission and distribution is the fact that transmission investment decisions may have material consequences for the flows of electricity between jurisdictions and for market outcomes. For this reason, the transmission arrangements already incorporate an element of strategic, national planning with the Annual National Transmission Statement (ANTS) by NEMMCO, and ERIG recently has recommended that the role of an independent entity in transmission planning be enhanced. We do not consider there to be material benefits from an independent conduct of the assessment/consultation process for distribution projects. However, we recommend a highly transparent environment in relation to the distribution network planning function.

The discussion of the proposed national planning regime is divided into the three main components of the regime, namely:

- the annual planning process and associated information disclosure that the DNSP will be required to undertake;
- the specific (additional) process that the DNSP will be required to undertake in relation to a particular project; and
- the means by which the regime is to be enforced, including whether there is some form of dispute resolution process available to disaffected parties.

It is noted, however, that the three components of the regime are interrelated. In relation to DSR or DG that may offer an alternative to network investment:

- the information presented in the annual planning process will alert the proponent to possibly emerging opportunities, and permit it to be registered to be kept informed;
- when the time to address the constraint becomes near and the project is sufficiently material, the specific process provides the DSR or DG proponent with the ability to make a proposal and have it evaluated through an appropriately robust process; and
- the regime may be enforced against the distributor.

Having noted the interdependencies, these elements are addressed in turn.

**2.3.1. Annual process**

A number of detailed design issues arise with respect to the annual planning and reporting obligations on the DNSPs, which include:
the scope and format of information that is required to be released in the annual plan;
§ the planning horizon over which constraints and proposed responses should be identified;
and
§ the other compliance-related reporting that should be included.
These are discussed in turn.

2.3.1.1. Reporting format

Two key objectives for the annual planning regime are to create a discipline (through moral suasion) on the DNSPs to make efficient planning decisions and to provide information to potentially connecting parties to enable them to plan, including to choose where best to connect to the network or whether a non-network project may be viable. For large customers, the best region in which to locate may be one with surplus capacity to supply customers, in the case of a generator the best region may be one with surplus capacity to supply energy into the wider network, and in the case of a provider of non-network options (i.e. a distributed generator seeking to sell network support services or an aggregator of DSR), whether and where non-network solutions may be efficient is likely to depend upon the existence of constraints and the cost of network options to address them. Clearly, for these outcomes to be met, the outcomes of the annual planning process must be made public. Amongst other things, this will require a change to rule 5.6.2(f)). The information that is made public must be sufficiently broad in its coverage to address the needs of the different potentially connecting parties.

In addition, we agree with a number of the submissions to the RDGWG discussion paper on impediments to the uptake of renewable and distributed generation that all planning reports and consultations associated with network augmentation should be made available from a single point in order to maximise their accessibility. Given the planning-related responsibilities that NEMMCO has at present for transmission, and the ERIG proposal that these be expanded, NEMMCO would appear to be the most appropriate custodian of these reports – however, where the reports are made available is not a material issue (so long as the ‘where’ is well publicised).

The information that is released in the annual report must be sufficiently detailed to underpin efficient planning by all potentially connecting parties, including DSR and DG proponents, and be sufficiently common across DNSPs to minimise the administrative costs of such proponents that operate in multiple jurisdictions. Therefore, we agree with the draft national Code of Practice for Embedded Generation developed for the Utility Regulator’s Forum (draft CoPEG) in recommending a standard format using standard documentation for the annual plan and project assessments. This will act as a means of information provision to parties planning to make connection applications, as well as addressing information asymmetries that may currently act as a barrier to DSR/DG alternatives.

Turning to the exact information that should be released, this should include an identification of emerging constraints over the planning horizon and potential network solutions to those constraints. We also recommend that an overlay of engineering/economic analysis be

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performed and presented by the DNSP in its annual planning report. This could take the form of a $/kVA per annum assessment of the value of deferring a constraint. It could also be included in a high level summary in the form of a map identifying the magnitude of emerging constraints, as stipulated in New South Wales, which could provide a means for non-network proponents to identify easily those projects for which they might have a feasible solution.\textsuperscript{11} The publication of such information should go some way to lowering the cost for proponents to assess the value of non-network alternatives, and hence a barrier to their participation (see discussion of the RFP process below).

Moreover, given the importance of losses for customers’ costs of energy and for the benefits that DSR or DG projects may deliver, the annual planning reports should also contain the current and next forecast distribution loss factor for geographic areas (chapter 5 of this report discusses further how such loss factors should be calculated and their importance to connecting parties).

It follows from the discussion above that we consider that for an appropriate level of commonality in planning reports across jurisdictions, there should be a detailed statement of the requirements for the planning related publications, drawing on the requirements that currently exist in a number of jurisdictions. That said, we consider that detailed statements of that type would be inappropriate to include in the Rules. Rather, we recommend two levels of requirements on the distributors with respect to their annual planning and reporting activities, namely:

- high-level obligations on the distributors that are set out in the Rules; and
- a requirement on the AER to publish statements of specific requirements on topics that are prescribed in the Rules (which would include the contents of planning reports) that would be binding upon the distributors.\textsuperscript{12}

We would envisage that the AER would be required to follow prescribed consultation requirements for putting in place and amending these statements of detailed requirements, for example, the Distribution Consultation Procedures set out in Part H of the proposed new Chapter 6 of the National Electricity Rules.

### 2.3.1.2. Planning horizon

There is a trade-off between the DNSP providing information that meets the planning requirements of interested parties and the accuracy of the forecasts and the cost to the DNSP as the planning horizon extends.

Parties who are required or choose to contribute to dedicated network assets or upstream augmentations – depending on where they choose to connect – would benefit from information regarding the future timing and location of network constraints, in particular, for

\textsuperscript{11} The New South Wales demand management code of practice stipulates that DNSPs should produce a map identifying the magnitude of emerging constraints; the example it provides shows the most critical capacity constraints expected to emerge over the next five years.

\textsuperscript{12} The proposed means of enforcing such obligations is discussed in section 2.3.3, below.
the planning horizon to extend to any constraint that would affect their connection point choice. This is of particular relevance to large users and to DG.

For proponents of non-network solutions to an emerging constraint, parties would benefit from having information on constraints sufficiently in advance to plan their own response, which includes having forecasts on demand growth and other relevant inputs that is sufficiently in advance so that the period over which a non-network option may defer a network option may be estimated (which is of special relevance to DSR). The discussion accompanying the Utility Regulator’s Forum’s draft National Code of Practice for Embedded Generation identifies that in determining the benefits offered by DG it is necessary to have a clear identification of the future network investments required to meet projected customer loads:

These projections of network investment provide the basis for much of the network deferral incentive that DG could potentially receive. The market must be provided with sufficient information regarding future network investment without becoming overly speculative. Some distribution augmentations presented by distributors a few years in advance may include uncertainties and/or be lacking in detail and this may not be sufficient to capture the full deferral benefits possible from EG.


All of the parties noted above also rely upon (or are intended to rely upon) the information produced for making various decisions, and hence also require information that is as accurate as possible.

Clearly, some judgement is required as to the period over which the distributors are required to plan and to publish planning related information. The transmission companies are required to adopt a 10 year planning horizon; however, as discussed above, future constraints and possible projects can be forecast with more confidence for transmission. We note that the Rules currently require the distributors to undertake their planning activities over a minimum period of 5 years ahead, which we propose to continue in the new national framework. We note that this period differs to the requirements in some states, but also note that the Rules can be amended reasonably expeditiously if this period proves to be too long or too short.

2.3.1.3. Compliance-related reporting

As noted above already, the annual planning reports in South Australia and New South Wales require reporting on the DNSPs’ compliance with their planning-related obligations, and the transmission planning regime requires transmission companies to use the annual planning report to explain their application of the regulatory test to projects that are small transmission assets but not large transmission assets (i.e. have a cost of between $2 million and $10 million).

We consider that reporting on such matters in the annual planning report provides a useful means of encouraging compliance with planning-related obligations and for raising the confidence of market participants in the planning process. We also recommend extending to distribution the transmission model whereby the results of the application of the regulatory test to projects that are below the threshold for a case-by-case assessment (but above a minimum threshold) are reported annually. This reporting would be included in the distributor’s annual planning report (this matter is discussed in section 2.3.2).
Recommendation 1.

The Rules should require DNSPs to undertake an annual planning process and publish an annual planning report that sets out the outcomes of that planning process. The annual planning report should include:

- a 5-year forecast of potential constraints, together with preliminary estimates of the costs of network solutions;
- a forecast of areas of substantially under-utilised existing transfer capability;
- a forecast of average and marginal distribution loss factors for different points in the network over the planning horizon; and
- a description of the DNSP’s compliance with their planning-related obligations, including:
  - a summary of case-by-case applications of the regulatory test completed in the previous year, and on the status of the relevant projects (and the status of any projects from previous years); and
  - the results of applying the regulatory test to projects below the threshold for a case-by-case process but that meet the threshold for transparent reporting and the status of the relevant projects (and the status of any projects from previous years).

The annual planning reports (and any other planning-related information) should be made public and available from a single point (such as the NEMMCO website).

Recommendation 2.

The AER should be required to produce a statement of specific requirements that is given effect by the Rules that sets out the standard format and required contents of the annual planning report.

The Rules should set out the matters the AER’s statement of specific requirements is permitted to address, which should include:

- requiring an accessible summary of where and when constraints are expected to emerge over the planning horizon and of the value of deferring the associated network augmentations (e.g. in $/kVA per annum terms);
- requiring an accessible summary of the extent of surplus capacity at different points in the network;
- requiring an accessible summary of the magnitude of current and forecast average and marginal distribution loss factors at different points in the network; and
- requiring a standard format for reporting on applications of the regulatory test.

2.3.2. Project assessment

The central component of the distribution planning arrangements currently provided for in jurisdictional arrangements or chapter 5 of the NEL – and as proposed in this report – is a
requirement for the DNSPs to undertake an economic cost-benefit assessment of alternative projects. A key part of the means of ‘enforcing’ such an obligation – and to ensure that the DNSP’s analysis is fully informed – is to ensure that the test is undertaken in an environment of transparency.

In the existing jurisdictional arrangements, an important part of the case-by-case project assessment the DNSP is required to undertake is a requirement for it to seek a formal ‘request for proposals’ (RFP) from potential providers of non-network solutions. The intention is that these providers would have had sufficient information through the DNSP’s annual planning process and report to plan for the emerging constraints and to have notified their interest. The RFP process then is the formal means for the non-network provider to place an alternative bid to the network solution. The RFP process also provides an efficient means of circumscribing the non-network alternatives that the DNSP must consider.

We support the use of the RFP process as a means of giving providers of non-network solutions a mechanism to be considered in the project assessment, while simultaneously circumscribing the range of non-network solutions the DNSP is required to consider. In particular, circumscribing the scope of the project evaluation in this manner will reduce the cost to the DNSP of administering the regime, consistent with the design principles set out above.

There are three key issues that arise in the design of the project assessment regime, namely:

- the threshold that is to be applied for case-by-case evaluations;
- the design of the RFP process; and
- the form of the cost-benefit test that is required to be applied.

These matters are addressed in turn.

2.3.2.1. Threshold for the case-by-case assessment and reporting

There are three separate thresholds that could be included in the distribution planning arrangements, namely:

- the threshold over which an economic evaluation is required to be performed, consulted on and reported on a case-by-case basis;
- the threshold over which a RFP should be issued and expressions of interest sought from potential providers of non-network solutions to network constraints; and
- the threshold over which the DNSP should be required to publish the results of project evaluations as part of the annual planning report that did not meet the first of the thresholds above.

The reason for having such thresholds is to avoid imposing a regulatory requirement that creates a compliance cost that may not be offset by the benefits created. Accordingly, the thresholds themselves reflect an implicit assessment of the point at which the potential benefits of performing the mandated activity is outweighed by its costs. For each threshold the potential benefits are savings on network augmentations, either through the identification of more efficient network solutions or through deferral of the augmentation by means of a
non-network solution. The question is then whether there is some level of network investment at which the effort and cost of the mandated activity would exceed these potential savings.

The thresholds that exist under the existing regimes differ substantially. Taking each of the three thresholds above in turn:

**Economic evaluation, consultation and reporting on a case-by-case basis: **

- **Transmission:** $10m (although we note that a separate report is also required for small transmission assets that are identified subsequent to the Annual Planning Report).
- **Distribution (Rules):** $10m
- **New South Wales:** $200 000
- **South Australia:** $2m

**Issue RFP from potential providers of non-network solutions:**

- **Transmission:** $10m: for large network assets, as part of the regulatory test the TNSP must request information to identify non-network alternatives.
- **Distribution (Rules):** no specific requirements to request information (beyond the consultation requirements above) or proposals.
- **New South Wales:** $200 000
- **South Australia:** $2m

**Publish economic evaluations but not consult or publish results on a case-by-case basis:**

- **Transmission:** $1m (although, as noted above, a separate report is required for small transmission assets that are identified subsequent to the Annual Planning Report).
- **Distribution:** $0-10m. (While clauses 5.6.2(g)-(h) are not entirely clear, they imply that an economic evaluation must be conducted for all augmentations, and the results published in a report, although consultation is only required for large network assets.\(^{13}\))
- **New South Wales:** $200 000
- **South Australia:** $2m

It is noted here that the fact that the New South Wales and South Australian regimes align the threshold for the application of a case-by-case (public) project assessment with the threshold for conducting a RFP reflects the objective of those regimes as being to minimise any bias

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\(^{13}\) Strictly speaking – as 5.6.2(f) is construed in terms of augmentations that would not be small distribution network assets – the consultation process should apply to assets of estimated $0-1m capitalised expenditure as well as to large distribution network assets. We assume that this is a drafting error.
that may exist against non-network solutions. In contrast, the design of the transmission regime reflects the more general concern to encourage the transmission companies to plan and invest efficiently – and hence is equally concerned with the choice between two network solutions as between a network and non-network solution. The view taken in this report is that the predominant concern for the planning arrangements is that, in the absence of robust incentives for efficient network investment by DNSPs, it is important to seek to influence the DNSPs’ planning decisions generally (irrespective of whether the decision is between network solutions or between a network and non-network decision). However, as a subset of this broader objective, encouraging non-network solutions to be evaluated on a neutral basis is important.

In the absence of significant implementation of non-network alternatives to-date, actual cost-benefit analyses of the different thresholds would not be useful. We have therefore been guided by the following three principles, with the following results:

- There is some threshold above which it should simply be assumed that the benefits of transparency (see section 2.1.1) are worth pursuing, and the activities described under the first threshold undertaken.

- The first two thresholds should be aligned, as is implicitly assumed in the New South Wales and South Australian arrangements: if it is worth undertaking a detailed economic evaluation of alternatives, then it should also be worth seeking out information on non-network alternatives and proposals from their proponents. However, in order to limit this threshold to a reasonable level, we propose to adopt South Australia’s threshold of $2m. We note that the New South Wales threshold of $200,000 meets the current catch-all requirement in the Rules (clause 6.2.3(e)(2)) that non-network alternatives should be considered before any network augmentation is undertaken. It therefore does not act as a filter, and we consider that it would impose unnecessary costs on the DNSP and may actually reduce the likelihood of feasible responses from non-network proponents (if it floods the market with unnecessary requests).

- There is some minimum level at which a network augmentation should be undertaken without a requirement to seek information on non-network alternatives, but where a project assessment should be undertaken and where there is still value in reporting these activities in order for transparency to be brought to bear. We therefore recommend that the third threshold discussed above should be $500 000 (cutting off at the upper limit of $2m).

A separate question is whether a process should be introduced whereby the DNSP would screen projects in order to consider the feasibility of non-network solutions, and only issue an RFP in those cases that the feasibility of non-network solutions was established (as in ESCOSA’s final decision on Guideline 12). The reasons for doing this would be:

- if there were substantial costs to the DNSP in preparing an RFP; \(^{14}\) or

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\(^{14}\) ESCOSA in its review of Guideline 12 identifies that the typical cost to ETSA Utilities of issuing an RFP is $30-35 000. For projects above the threshold of $2m, which require an RFP, this represents less than 2% of the project cost.
if issuing RFPs for projects with no feasible non-network solutions decreased the likelihood that proponents of non-network proponents gave due consideration to the requests where there is a greater potential for non-network options to be successful.

We have not recommended such a screening process because we have recommended case-by-case evaluation and reporting for any project over the threshold of $2m (i.e. a reasonably high level, especially compared to the current level in New South Wales). We also note that:

if there were a screening process then DNSPs would still need to report on projects where the distributor did not think a RFP should be issued; and

as long as non-network proponents can easily identify whether a project is relevant to them, then they should be able to concentrate only on those that are. This is a matter for the design of the tender documentation and is captured in Recommendation 5 accordingly.

Recommendation 3.

For any project to alleviate a network constraint for which the network solution would require an estimated capitalised expenditure of $2m or more, DNSPs should be required to perform an economic cost-benefit assessment of that project (see recommendation 6). As part of this assessment, the DNSP should be required to consult publicly and be required to issue an RFP from potential providers of non-network solutions to the network constraint. The DNSP should be required to report publicly the results of its assessment immediately after its assessment has been completed, and also to summarise the outcomes of the assessment in its annual planning report (see Recommendation 1).

Recommendation 4.

For any network constraints for which the network solution would require an estimated capitalised expenditure of $0.5-2m, DNSPs should be required to undertake an economic cost-benefit assessment of the project and publish the results in the annual planning report, without being required to issue an RFP or consult on the options.

We observe that for network constraints for which the network solution would require an estimated capitalised expenditure of less than $0.5m, there would be no formal ex post reporting requirement: DNSPs would not be required to undertake an economic cost-benefit assessment of the project, to issue an RFP or to consult on the options. The ex ante requirement to identify emerging constraints in the annual planning report would, however, apply to projects of this magnitude.

2.3.2.2. Design of the Request for Proposal Process

Potential proponents of non-network solutions have suggested that the cost of preparing proposals for non-network solutions is high. This would be less important if the main proponents were always large, well-resourced energy companies. It might, however, deter smaller, less well-resourced companies, or simply those that try to make a proposal and are unsuccessful. Repeated and costly failure will ultimately undermine the credibility of the whole planning process. While it has been proposed that this problem could be fixed by
permitting proponents to pass some or all of these proposal costs through to the DNSP, we agree with ESCOSA’s finding in its review of Guideline 12 that this would be inappropriate as it would amount to subsidising – rather than removing barriers to – these projects.

That said, it is important for the RFP to provide DG or DSR proponents with sufficient information on the potential for non-network options to be a lower cost solution than the network solution to decide whether it is worthwhile to submit a tender. For these projects, the cost of preparing bid documentation can be a material proportion of the value of total cost of their projects. As a minimum, this information should include an estimated range of costs for network solutions. If these have altered significantly from those published in the project plan then they should be updated. In addition, the RFP must also set out in clear terms the technical requirements that the non-network solution would need to satisfy, so that proponents can evaluate the technical suitability of their proposed project. We consider that it would be appropriate for the AER to issue a (binding) statement of specific requirements that sets out in detail what is required to be included in a RFP, including requirements to ensure that the form and contents of such requests are consistent across the national electricity market.

An additional step that could be taken is for the DNSP to compile information relevant to the feasibility of DSR or DG in an area, and include it in the information that accompanies the RFP. This activity is a legitimate activity for a network business that is seeking to minimise its cost of supply. At this stage, we do not propose to mandate such a role for DNSPs, but note that it would be appropriate for such activities to be treated as part of its regulated activities. In addition, a requirement for DNSPs to compile information relevant to the feasibility of non-network solutions could also be introduced in the future if it was considered appropriate.

It is noted here that one downside of publishing the likely network costs is that providers of DSR or DG may not bid the cost of their options, but rather an amount that is just below the cost of the network solution. However, even were this to occur, customers would be no worse off, as they would still pay prices that are no higher than would have applied if the network options had been employed. Moreover, if competition in the provision of non-network options develops, there will be pressure for the bid price of non-network options to be pushed towards their own cost.

While the RFP would not seek other ‘network’ solutions for the project, it would be open to parties to identify during the consultation if they thought that a more efficient network solution existed, and possibly make use of dispute mechanism proposed in section 2.3.3 of this report if directly affected by the outcome.

Turning to the process surrounding the RFP, a matter of key importance to providers of non-network solutions is the time they have to prepare their proposals. There are some difficulties in specifying the timings that should apply in the RFP process. On the one hand it is desirable to maximise the scope for non-network proponents to prepare their cases and respond to an RFP. On the other hand, the process must fit in with the DNSP’s need for a committed project by the time it would otherwise have to commit to the network augmentation itself. The required lead time for the DNSP will depend upon the network option, and may also be affected by the applicable service standards, and so vary between jurisdictions. We consider, therefore, that it would be difficult to define these timeframes in
the Rules. Rather, the AER should be tasked with providing additional guidance as to the timelines for RFP processes in the statement of specific requirements noted above. The AER’s decision in this regard should be subject to the guiding principle that sufficient time should be provided for proponents of non-network solutions to prepare their cases while allowing the DNSP to implement the network solution should it be the efficient option.

As a related point, we note that if the DNSP is to accept a non-network alternative to a network augmentation, then there is a need for a point of closure in the RFP process – that is, for the proposal in relation to the non-network option to result in a binding agreement with the DNSP (and with delivery obligations on the non-network provider). For instance, this may mean that responses to an RFP should take the form of an offer capable of immediate acceptance, or if they are subject to further negotiation, that they should be subject to a requirement that the parties come to an agreement within a reasonable timeframe. We consider that the AER should be empowered, as part of its role in setting out the contents and process for the RFP process discussed already above to issue appropriate requirements for how the RFP process should be brought to a closure.

Recommendation 5.

The Rules should require the AER to issue a statement of specific requirements that sets out the contents of a Request for Proposals for non-network solutions to address an emerging network constraint and that sets out the process to be followed in issuing such requests.

The Rules should require the AER statement to require the RFP to include, at a minimum:

- the technical requirements that the non-network solution would need to meet;
- the estimated range of costs for network solutions and an indication of the resulting annual cost that a non-network solution would need to better in order to be selected; and
- an indication of whether the DNSP considers non-network alternatives to be a feasible solution for the project.

The Rules should require the AER statement to require the RFP process at a minimum to:

- provide sufficient time for proponents of non-network solutions to prepare their cases while allowing the DNSP, in the absence of a committed non-network project, to implement a network solution after a cut-off date; and
- ensure that the RFP process is be capable of being brought to closure, with the non-network solution either committed (and bound) to deliver in a reasonable period of time, or the DNSP free to select an alternative option.

The Rules should require all RFPs to be published in the same central location as the annual planning reports.
2.3.2.3. Form of cost-benefit test for distribution augmentations

The discussion has referred to the need for the DNSP to apply an economic cost-benefit test to determine the most efficient means ofremedying an emerging distribution constraint (assuming it is efficient to remedy that constraint). The application of a cost-benefit test means that the DNSP is required to stand aside from what may be in its (private) commercial interest, and instead to assess the costs and benefits of particular options from society’s point of view. The matter discussed in this section is the precise form of that cost-benefit test.

The Rules require the AER to promulgate a cost-benefit test to be used by NSPs to assess the relative merits of different network or non-network options for resolving constraints (and, implicitly, for testing whether it would be efficient to resolve the constraint), which is referred to as the regulatory test. In essence, the regulatory test is a method for applying a (theoretical) cost-benefit assessment to the practical case of electricity network investments. The need for such a test derives from the fact that applying a cost-benefit test to any particular real-world case requires a plethora of assumptions and simplifications to be made, and as a result, careful judgement is required to ensure that the results of the test remain robust.

The regulatory test as it currently exists has two limbs, which are:

- **for reliability projects** – where TNSPs are required by their reliability obligations to deliver a certain outcome, the test is passed if the TNSP selects the lowest cost options from the class that would meet the particular reliability need; and

- **for other projects** – the TNSP is required to forecast the market benefits of the alternative projects for resolving a particular network constraint, compare this to the costs of each project and select the project that maximises the net benefit (i.e. the difference between benefits and cost). Given that there is uncertainty over many of the inputs into this analysis, the projects need to be compared for a number of different scenarios (e.g. demand growth) and sensitivities for key inputs (e.g. the discount rate).

The benefits that are typically counted for a transmission augmentation under the second limb include the saving in generation costs over the short run if resolving the transmission constraint allows the dispatch of a lower cost generator, permitting the capital cost of generation over the longer term as new entry is able to be deferred (as better use is being made of existing plant) and potentially sited in a lower cost location in the future, and improvements in reliability to customers.

As discussed above, the national arrangements refer to a ‘cost effectiveness test’ being required to be undertaken for distribution augmentations that pass a threshold. The term ‘cost effectiveness test’ refers to only the first of the limbs described above. The reference to only the reliability limb for DNSPs assumes that all of the DNSPs’ augmentations are driven by prescriptive reliability obligations, which is not the case. Rather:

- some DNSPs – such as those in Victoria – have discretion under the regulatory regime regarding the level of reliability to be provided, and are encouraged to trade off cost against benefit (in terms of the value of the reduction in expected unserved energy); and
there may be cases where an augmentation may be undertaken to increase the transfer capability from an embedded generator, in which case wider benefits (such as a reduction in generation operating costs, or losses at least) should be counted.

Accordingly, the reference only to the first of the limbs would lead to potential benefits being ignored, with the possibility that the most efficient project would not be selected. This is of particular importance where one of the alternative projects is a network support agreement with a DG, and where the reduction in losses caused by the DG is likely to be material in the comparison of the relative economic benefits of the projects. Accordingly, it is essential that both limbs be available to DNSPs when evaluating projects, which would be achieved by requiring the DNSPs to simply apply the standard regulatory test. We note in this regard that one of the design principles for the regulatory test the AER is required to promulgate is that the test:  

not require the level of analysis to be disproportionate to the scale and size of the new network investment (NER, clause 5.6.5(c)(6)).

The draft CoPEG identified the following benefits of DG:  

- Lower capital cost of generation (through the mass production of small, standard generation sets);  
- Smaller incremental increases in generation capacity to more closely match demand, minimising under-utilisation;  
- Reduction in environmental emissions; and  
- Potential for enhanced security of supplies (through island operation, for example, where embedded generation may serve a limited number of customers through a local healthy network which may be isolated from the faulty network) and improved power quality (power quality improvements may include voltage support and loss reduction in some cases).


All of these benefits except for the third (environmental benefits) can be taken into account at present when applying the standard regulatory test. Regarding the environmental benefits, we note that the implicit assumption in the current test is that broader policy tools should be used to account for environmental externalities—such as a tradable emissions scheme—on which we consider to be a reasonable approach.

Two states, South Australia and New South Wales, have adopted their own provisions requiring DNSPs to engage in a similar cost-benefit exercise to evaluate options for relieving constraints that they identify. These frameworks both specify that options be evaluated according to the net annualised cost of providing system support. This includes the cost incurred by the distributor plus the cost or benefits of changes to transmission and distribution losses. The inclusion of the net cost/benefits of changes to losses is designed to

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15 It is noted that COAG has recently agreed to amendments to the current form of the regulatory test in light of ERIG (2007)’s recommendations. As part of this process the AEMC will be asked to advise on amalgamating the two limbs of the regulatory test. If this amendment is made then the cost effectiveness limb would be removed as a separate test in any event.
supplement a narrow test to include the wider cost and benefits that some non-network solutions offer. However, while the inclusion of losses in the class of potential benefits is an important advance from a pure cost-effectiveness test (particularly for DG), other classes of benefit should also be able to be included in an evaluation.

That said, however, it is important for the ability to remain for the DNSPs to apply the regulatory test in a manner (and with a level of sophistication) that is appropriate for the case at hand. It was noted above that the vast majority of a DNSP’s augmentations relate to meeting reliability needs, and so it is important for potential wider economic benefits to be ignored were they are likely to be immaterial. Similarly, the analysis required to be undertaken of DG or DSR alternatives to network augmentation should be proportionate to the scale of the project and the actual prospect that a non-network solution may be the efficient option. Thus, we consider that the continuation of a clause in the Rules along the lines of clause 5.6.5(c)(6) – as quoted above – is an essential component of the detailed specification of the cost-benefit test that is to be applied by the DNSPs.

**Recommendation 6.**

DNSPs should be required to apply the standard regulatory test (rule 5.6.5A) when undertaking a cost-benefit assessment of alternative projects (requiring amendment to clause 5.6.2(g)) so long as it continues to provide the flexibility for the test to be applied in a manner that is proportionate to the size and scale of the project.

### 2.3.3. Regulatory oversight of the planning requirements

An important issue to consider is how the DNSP’s compliance with the planning regime should be secured. One of the matters that need to be addressed in this regard is the extent to which parties who may be affected by the DNSP’s planning decisions should have a right to challenge those decisions, and then the effect of a successful challenge.

Regarding the DNSPs’ obligations to publish information annually, we see no reason for these obligations to be treated any differently than Rules obligations generally. That is, like with other Rules obligations, the AER has the role of assessing whether the DNSPs comply and to seek appropriate remedies should the DNSPs be adjudged not to be complying. As part of this process, any party may raise with the AER concerns about a particular DNSP’s compliance, which in turn would inform the AER’s investigations. The Retail Policy Working Group’s Composite Consultation Paper (June 2007) deals with enforcement mechanisms in the transfer of non-economic distribution and retail regulatory functions to the national framework. It recommends provisions for the NEL that would support the AER’s compliance monitoring and enforcement functions. These include an obligation on regulated entities to undertake compliance audits, and to co-operate with such audits being undertaken by the AER or an independent auditor, in accordance with guidelines issued by the AER. If such a provision were introduced, it would be appropriate for the AER to rely on it when enforcing these obligations.

Equally, it may be found that a DNSP is complying with the relevant Rules and subsidiary regulatory instruments (e.g. detailed requirements issued by the AER that are given effect by the Rules, or non-binding general guidelines issued by the AER), but that the regime is ineffective as a result of a defect in those instruments. In this case, it would be open to any
party (including the AER) to propose a change to the Rules. It would also be open to the AER to amend its statements of specific requirements or any (non-binding) guidelines issued (that is, after following the prescribed process), and open to any party to raise with the AER any concerns about the operation of these instruments.

A more complex issue arises in respect of a DNSP’s assessment of a particular project. The key means through which DNSPs’ (and TNSPs’) project evaluation decisions are overseen is through the requirement for the process to be transparent, with reasons given for the relevant network service provider’s choice. The intention is that transparency will create moral suasion for appropriate decision making. In addition, with case-by-case project assessments, in this situation, there may be a party who is directly affected by the DNSP’s decision – such as a DG or DSR proponent whose bid was found to be inferior to the network solution, in contrast to the situation of a DNSP’s annual planning activities. Consequently, the Rules currently provide scope for disaffected parties to dispute a NSP’s decisions. In particular:

Transmission assessments – a range of parties (including interested parties) can activate a dispute resolution process for regulatory test assessments for new large transmission assets (currently projects that have a cost in excess of $10 million). The scope of matters that can be disputed is limited, especially for projects that are judged to be for reliability reasons. The AER hears the dispute.

Distribution assessments – Registered Participants may dispute the recommendations of a project evaluation report for new large distribution assets (currently projects that have a cost in excess of $10 million) or where the project will change the Registered Participant’s DUOS charges by more than 2 per cent. If a dispute is lodged, the DNSP and Registered Participant are required to negotiate in good faith – which triggers the general dispute resolution processes in Chapter 8 of the Rules if agreement cannot be reached.

The effect of the dispute resolution process is subtle, however. The dispute resolution body cannot direct the NSP as to what it can or cannot construct. The economic regulator could have regard to the outcomes of a project evaluation (and a dispute thereto) when assessing whether the costs for a certain project should be included in regulated charges. However, this course is only open to the regulator to the extent that it is required or empowered to undertake a test of the prudence of expenditure, which is limited in the revenue setting Rules for transmission (and those proposed for distribution). Accordingly, to a large extent, the existing dispute resolution processes enhance the environment of transparency, rather than regulating directly the NSP’s decisions. It is noted that the ERIG (2007) report noted the role of the regulatory test for transmission in improving the degree of transparency in relation to planning decisions.

Our view is that it would be appropriate to insert in the Rules a dispute resolution process for distribution planning activities that is similar to that which currently applies for transmission through rules 5.6.6(j)-(n) but with some changes. The key features of the process should be:

threshold – a threshold should be set to restrict the process only to sufficiently material situations, which should be set at the current level for distribution (i.e. new large distribution assets, which are therefore reported on a case-by-case basis);
parties to the dispute – parties directly affected should be able to lodge a dispute, which would include proponents of non-network options, end-users and agents on their behalf. The current restriction to only Registered Participants for distribution is inappropriate;

scope of the dispute – we see no basis for significantly limiting the scope of the dispute given the role of the process is to enhance transparency (i.e. the elements of rule 5.6.6(j) which limit the scope of the dispute should not be replicated for distribution);

dispute resolution process – the AER should have the role of hearing the dispute and adopt a low cost process for this; and

effect of the dispute – the current effect of the mechanism, whereby the DNSP cannot be directed in its activities, should be maintained.

We note here that, even absent the dispute resolution process, the requirement for DNSPs to undertake the project evaluation, and the form of that evaluation, would be Rules obligations. Accordingly, the AER would have the scope to take measures to require the DNSP to comply with these obligations, irrespective of the scale of the project.

Recommendation 7.

The DNSP’s obligations to undertake the annual planning and reporting activities, and to undertake project evaluations, should be Rules obligations and able to be enforced through standard Rules-enforcement processes.

Recommendation 8.

A dispute resolution regime based on rules 5.6.6(j)-(n) should exist in relation to the DNSP's conduct of a cost-benefit assessment (and associated RFP for non-network options) for particular distribution projects, which should have the following features:

threshold – should be limited to projects that are new large distribution assets (currently projects whose total capitalised cost is $10m and above);

parties to the dispute – extend to parties directly affected, which would include proponents of non-network options, end-users and agents on their behalf;

scope of the dispute – should not be significantly limited;

dispute resolution process – the AER should have the role of hearing the dispute and adopt a low cost process for this; and

effect of the dispute – the current effect of the mechanism, whereby the DNSP cannot be directed in its activities, should be maintained.

2.3.4. Further issues

2.3.4.1. Overcoming ‘cultural barriers’ to DSR/DG

The DNSPs require a degree of ‘firmness’ or confidence in non-network solutions before they will actively consider those solutions – and particularly demand side response options –
given that much of the risk of a network failure inevitably sits with the DNSP. Even if a contractual mechanism is established protecting the DNSP from contingent liabilities (such as the risk-sharing arrangements recommended by NERA and Allen Consulting Group, March 2007), a major outage caused by the failure of demand management solution will negatively affect a DNSP’s performance targets and standing in the community; it can also have political ramifications.

Therefore, even with a prescriptive and transparent planning regime, to improve uptake of DSR/DG will require a growth in the degree of trust placed in and understanding of the services provided. This could grow out of good communication between the parties and trials where non-network alternatives could prove their worth in practice. However, to facilitate trust and communication, DNSPs may require a direct incentive.

In response to concerns that the regulatory framework provided little incentive for investment in research and development, particularly in relation to networks responding to increasing DG connections, Ofgem developed a specific incentive arrangement in its regulatory framework to encourage network businesses to invest in research and development. Ofgem decided that there were impediments in the existing regulatory framework for efficient investment in research and development because the cost efficiency benefits that resulted would be passed through to customers at the next regulatory review. Ofgem found that this was likely to lead to less than efficient investment in research and development, which warranted the inclusion of a specific incentive mechanism for research and development expenditure in the regulatory framework.

The Ofgem mechanism is called the Innovation Funding Incentive and allows the business to seek regulatory approval for specific research and development projects within set limits. The costs of these projects are then recovered through the revenue allowance. These additional funds are also ring-fenced from the revenue allowance, with strict reporting requirements, to ensure that there is no incentive for the businesses to reduce expenditure on research and development to achieve cost efficiencies within the regulatory period.

Whilst there is potential for similar impediments to efficient research and development investment to arise from the regulatory framework provided in the Rules, we are unaware of concerns that DNSPs are not investing sufficiently in research and development. This may however warrant further specific investigation in the future.

**Recommendation 9.**

The Rules should ensure that DSR/DG trials and risk sharing arrangements are encouraged in order to build trust and communication between DNSPs and proponents of non-network alternatives.

In addition, the regulatory framework should be reviewed to determine whether insufficient incentives are provided to DNSPs to invest efficiently in research and development.

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16 Office of the Gas and Electricity Markets, which supports the Gas and Electricity Markets Authority, the regulator of the gas and electricity industries in Great Britain.

development, warranting the development of a specific incentive mechanism in the Rules.

2.3.4.2. Links with Chapter 6 of the National Electricity Rules

The main link between Chapter 6 and the planning-related measures described in this chapter stems from the rationale for imposing these measures that were discussed at the start. That is, the expectation that the DNSP’s financial incentives with respect to investment decisions (which are the product of Chapter 6 of the Rules) are unlikely to be aligned with economic efficiency. Thus, as a result of the inadequacies of the arrangements under Chapter 6, the planning-related measures that have been described in this chapter are warranted.

However, there are other potential links between the planning-related measures in this chapter and Chapter 6 of the Rules that could be envisaged, which include:

β for the AER to be permitted at a price review to test the prudence and efficiency of a DNSP’s investments made during the previous regulatory period, which may be based (at least in part) on the results of the regulatory test; and

β where the regulatory test that is conducted, to link the amount that is included in the DNSP’s regulatory asset value to the estimate of the cost of the relevant project that was used in the regulatory test assessment, in order to try to provide the DNSP with the incentive to use an unbiased forecast of the project cost in that assessment.

The exposure draft of the new Chapter 6 of the Rules would rule out the first of these links, as it is proposed for all capital expenditure to be included in the DNSP’s regulatory asset base, irrespective of the outcome of the regulatory test, although the option of prudence / efficiency reviews have existed under the previous jurisdictional regimes. Whether or nor the first of these measures is considered appropriate depends upon one’s views about the risk that is imposed from the threat of a prudence / efficiency view, compared to the likelihood that a DNSP will spend inefficiently.

We do not favour the second of these links, that is, a direct link between the DNSP’s regulatory asset base and the assumptions used in the regulatory test (and note that these values have not been linked to date). In particular, estimates of the cost of projects have a high degree of uncertainty at the time of the conduct of the regulatory test, and hence only permitting the DNSP to recover this value could expose it to excessive risk. Moreover, where the network option was clearly preferred, a strong incentive would be provided for the DNSP to bias upwards its estimate of the cost of the network option, and hence make a windfall gain.

2.4. Consistency with National Electricity Market objective

The proposed amendment to section 7 of the NEL provides that:

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18 That said, if DNSPs ignore or manipulate the regulatory test in order to serve their own interests at the expense of overall efficiency, we would expect a rule change to permit a prudence / efficiency test to be applied in the future, the threat of which would be expected to discipline the DNSPs now.

19 Section 9, of the exposure draft of National Electricity Law Amendment Bill.
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, reliability and security of supply of electricity; and
(b) the reliability, safety and security of the national electricity system.

The proposed network development and planning framework promotes the market objective by:

- **Promoting efficient investment through application of economic benefit criteria to planning**
  
  By applying economic benefit criteria to DNSP network investment, additional incentives are created for more efficient investment to result. The provision of additional information should also facilitate investments by embedded generators and other parties, which will further improve the scope for efficient investment to be promoted.

- **Promoting efficient investment through transparency of information**
  
  The proposed planning framework seeks to provide sufficient information to parties to allow for economically efficient investment and operational decisions to be made. Such information provision should – at least in part – address information asymmetries that may lead to inefficient investment decisions by connecting parties or those offering non-network solutions. The asymmetries occur because the network service provider is likely to possess greater knowledge of the network than third parties, and hence also of the likely costs and benefits of those parties’ intended actions. As noted by the Energy Reform Implementation Group in its draft report, planning and connection processes, and the information that is provided to stakeholders through these processes, are crucial and should be governed by the principle of transparency (ERIG 2006, Ch. 6).

- **Recommending regulatory measures that are proportionate**
  
  The costs and risks of imposing regulation should be minimised in order that they do not outweigh the benefits. In recommending the individual measures of the network planning and development framework, we have aimed to minimise their cost and to only require regulatory intervention where necessary, while still putting in place a framework that should promote the investment efficiency objectives of the NEM.

- **Harmonisation of differing jurisdictional arrangements should lower the cost of, and barriers to, participating in the market**
  
  Harmonisation of jurisdictional arrangements is expected to lower costs and barriers to participating in the market. It therefore underpins potential economies of scope and scale that may arise and is a key means by which non-pricing aspects of distribution should support the NEL objective.

### 2.5. Implications and transitional issues

The proposals set out here build on the arrangements currently in place in the jurisdictions. In particular most jurisdictions require the publication of an annual planning report with similar content. Our recommendations simply standardise this requirement and move it into the national framework on a consistent basis. For most large augmentations the process will remain similar to the requirements that already exist in the rules. However, DNSPs other than
those in New South Wales and South Australia, will be required to develop new protocols and procedures for screening, consulting and evaluating proposals for non-network solutions in the case augmentation proposals less than $10 million.

Currently the jurisdictional arrangements are achieved through a variety of means such as licence conditions supported by codes and guidelines or direct legislative direction. Migrating to a standardised national template promulgated through the rules and supported by AER statements will require coordination at the jurisdictional level and the removal of overlapping requirements. In some cases, such as in New South Wales and South Australia, this might require legislative change as both currently have laws requiring licence conditions be imposed on DNSPs that would duplicate the proposed national framework.
3. **A national framework for distribution network connection**

Jurisdictional legislators, regulators and the architects of the NER have developed specific provisions in relation to network connections that, in effect, seek to prevent a DNSP from exerting its monopoly power in the provision of network services, including through limiting or creating barriers to the efficient provision of network services. The potential for a DNSP to limit access to the network will be influenced by, amongst other things:

- the substantial bargaining power possessed by the DNSP, which by virtue of the DNSP’s monopoly position and asymmetric access to information may result in the prospective user:
  - being denied access, or if access is not explicitly denied then the DNSP may delay the connection process, or use other strategies to frustrate the connection process and in so doing limit access;
  - having to accept technical and other terms and conditions of access that are below the standard it has sought; and/or
  - having to pay connection charges associated with the construction of dedicated or extension connection assets that exceed the charges that could be expected to arise in an effectively competitive market;
- the prospective user’s technical requirements relative to the DNSP’s minimum and automatic access standards; and
- the assets that must be constructed to effect connection and the price of connection that will depend on:
  - the technical requirements of the prospective user;
  - the distance the prospective user is from the existing shared network; and
  - the market power possessed by the DNSP in relation to the construction of dedicated connection assets and extension assets.

The provisions that have been developed across the NEM jurisdictions and within the NER have, to varying extents, sought to minimise the potential exercise of monopoly power by DNSPs while also addressing the imbalance in the bargaining power possessed by the two parties and facilitating effective negotiations.

While there are some common features of the current network connection arrangements prevailing within each jurisdiction, the specific provisions enacted in each jurisdiction differ in their scope, application and level of prescription. The jurisdictional arrangements are also considerably different from those set down in the Rule 5.3 of the NER.

AAR has recently reviewed the jurisdictional arrangements pertaining to the connection of small retail load customers and has made a number of recommendations which will enable this class of customers to seek connection through a standardised connection process in accordance with the NER. In view of the work that has already been done in this area this
section of the report only relates to the network connection arrangements for users other than ‘standard’ small retail load customers (ie, large load, market network service providers, market customers, micro embedded generators (which may also be small retail customers), small DGs, medium DGs and large DGs). For the purpose of this review, we have also limited our consideration of connection arrangements to applications for connection to distribution networks.

The remainder of this chapter is structured in the following manner:

- Section 3.1 provides an overview of the network connection arrangements currently prevailing within the NEM and the recommended changes to these arrangements flowing from the NERA and Gilbert + Tobin Public Consultation Paper,20 the draft CoPEG21 and AAR’s Consultation Paper;22
- Section 3.2 sets out the proposed national framework for network connection; and
- Section 3.3 demonstrates the consistency of the proposal with the market objective contained in section 7 of the NEL.

### 3.1. Current connection arrangements

Before discussing the connection arrangements in place across each NEM jurisdiction, it is instructive to outline the interaction between jurisdictional arrangements and the NER. The connection procedures in the NER require DGs with a name plate rating in excess of 5MW23 and market network service providers (Registered Participants) to use the connection procedures contained in Rule 5.3. Rule 5.3.1(c) also allows any other person wishing to establish a connection to elect to use the procedures in the NER. In effect Rule 5.3.1(c) allows small load, large load, micro small and medium DGs to choose between jurisdictional arrangements and the NER (see Table 3.1).

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### Table 3.1: Application of connection arrangements to alternative users

<table>
<thead>
<tr>
<th>Type of User</th>
<th>NER</th>
<th>Jurisdictional Arrangements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Large embedded generators¹</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Market network service provider</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Market customer</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Small load (retail customers)</td>
<td></td>
<td>Choice to use the NER</td>
</tr>
<tr>
<td>Large load</td>
<td></td>
<td>Choice to use the NER</td>
</tr>
<tr>
<td>Micro embedded generators²</td>
<td></td>
<td>Choice to use the NER</td>
</tr>
<tr>
<td>Small embedded generators³</td>
<td></td>
<td>Choice to use the NER</td>
</tr>
<tr>
<td>Medium embedded generators⁴</td>
<td></td>
<td>Choice to use the NER</td>
</tr>
</tbody>
</table>

Notes:
1. Unit size greater than 5MW.
2. Unit size 2kW or AS4777 compliant.
3. Unit size greater than 2kW but less than 1MW.
4. Unit size greater than 1MW but less than 5MW or not greater than 1MW but connected to the high voltage network.

### 3.1.1. National Electricity Rules

The framework for connection in Chapter 5 of the NER applies to both transmission and distribution networks. However, for the purpose of this review our consideration has been limited to the connection arrangements for distribution networks. The remainder of this section examines the obligations of a DNSP to connect a user and sets out the pertinent features of the connection framework contained in Rule 5.3 including its interaction with other provisions within the NER.

#### 3.1.1.1. Obligation to connect

Rule 5.2.3(d)(1) imposes an obligation on a DNSP to review and process connection applications and to enter into a connection agreement with each Registered Participant and any other person seeking connection via clause 5.3 of the NER. Provisions within the Draft Chapter 6 rules further clarify the obligation of a DNSP to provide connection services with Draft Rule 6.1.4(2) stating that a DNSP must provide a direct control and negotiated distribution services on terms and conditions of access that are consistent with the requirements set out in Chapters 4-7 of the NER. Draft Rule 6.1.4(3) further states that a DNSP must not engage in conduct for the purpose of preventing or hindering access to those services.

#### 3.1.1.2. Connection framework

Rule 5.3 sets out the steps to be followed by a DNSP, Registered Participants and any other person (jointly referred to as applicants in Rule 5.3). Rule 5.3 is based on a negotiate-arbitrate model and is underpinned by the principles specified in Rule 5.1(3).

Rule 5.3 recognises six discrete phases in the connection application process, as summarised in Box 3.1. The dispute resolution mechanism applying to this process has recently been revised as part of the Draft Chapter 6 rules. In accordance with Part M of the Draft Chapter 6 rules, any dispute arising between the DNSP and applicant in relation to the terms and conditions of connection will be directed to the AER who will act as arbiter of both price and non-price disputes.
Box 3.1: Connection process phases

Connection enquiry phase (Rule 5.3.2)
In this phase the applicant advises the DNSP of its connection requirements. Within five business days of receiving this connection enquiry the DNSP may request further information of the kind specified in Schedule 5.4. Within ten business days of receiving the required information the DNSP must acknowledge the receipt of the enquiry and advise the applicant if it is the appropriate DNSP.

Response to the connection enquiry phase (Rule 5.3.3)
During this phase the DNSP is required to respond in writing to the connection enquiry within a defined period of time and advise the applicant of:
- the preliminary program for processing the application (within ten business days);
- the automatic access standards, minimum access standards and performance criteria for each technical requirement set out in Schedules 5.1-5.3(a) of the NER (Schedule 5.1 – System standards, Schedule 5.2 – Generators, Schedule 5.3 – Market Customers, Schedule 5.3(a) - Market Network Service Providers) (within twenty business days); and
- any additional information it would require to process the application including the technical details of the kind specified in Schedule 5.5, commercial information demonstrating ability to meet prudential requirements and the application fees (within twenty business days).

Application for connection phase (Rule 5.3.4)
Within the application for connection phase, the applicant must submit the technical and commercial information required by the DNSP. The applicant must also advise the DNSP if it is willing to accept the automatic access standards or will seek to negotiate a connection standard within the bounds set by the minimum access standards and the automatic access standards. If the automatic standard is accepted then the parties move on to the next phase. If the automatic standard is accepted then the parties move on to the next phase. If the applicant proposes to negotiate a lower connection standard it must be no less onerous than the minimum access standard and not adversely affect the power system security and the quality of supply to other users. The DNSP must advise NEMMCO of the proposal and, based on NEMMCO’s advice, the DNSP may accept or reject the proposed negotiated access standard. If the proposal is accepted then the parties can progress to the next phase. The DNSP may also reject the proposed standard if, in its reasonable opinion, the connection will adversely affect the supply of other users.

Preparation of offer to connect phase (Rule 5.3.5)
Having agreed on the access standards, the DNSP must then prepare an offer to connect. During this phase the DNSP may liaise with NEMMCO and other NSPs affected by the connection to determine the technical requirements of the connection, the extent and cost of augmentation.

Offer to connect phase (Rule 5.3.6)
Within the time specified in the preliminary program (or if a negotiated access standard is pursued the DNSP may extend the time program) the DNSP must prepare an offer to connect that is fair and reasonable and consistent with the safe and reliable operation of the power system. The offer to connect must:
- contain the terms and conditions contained in Schedule 5.6 which includes, amongst other things, the access standards and connection charges;
- set out the basis for determining distribution charges and prudential requirements (Chapter 6); and
- for generators and market network service providers comply with the access arrangement developed under Rule 5.5.

Negotiation of these terms and conditions must be conducted in good faith.

Finalisation phase (Rule 5.3.7)
Within this phase the applicant can accept the offer and if a connection agreement is formalised then NEMMCO must be advised.
The connection framework contained in Rule 5.3 also interacts with other provisions in the NER. The more notable of these are the provisions relating to connection charges, prudential requirements and access arrangements for generators and market network service providers, each of which is referred to in the offer to connect phase.

**Connection charges**

Connection charges generally reflect the costs associated with providing and installing dedicated connection assets, extension assets and in some cases augmentation of the shared network. The form of regulation that will apply to these charges depends on whether the AER defines the services as a direct control service or a negotiated distribution service. If the service is defined as a direct control service then charges will be regulated through a price cap, a revenue cap or both. If the service is defined as a negotiated distribution service then the terms and conditions surrounding this service must be negotiated within the negotiation framework developed by the DNSP (Draft Rule 6.7.5) and approved by the AER. The negotiated connection charges levied by a DNSP must also comply with the principles set out in the Draft Rule 6.7.1. A more detailed examination of these charges is set out in Chapter 4.

**Prudential Requirements**

In the offer to connect phase, DNSPs are required to set out the basis for the prudential requirements for connection service and/or the use of system service. Provisions relating to prudential requirements are contained in Draft Rule 6.21.1 and 6.22. In accordance with Rule 6.21.1(b) the prudential requirement is a matter for negotiation and may take a number of forms. Rule 6.22 further states that a prudential requirement may cover future revenue related to the provision of direct control service for any new assets installed as part of a new connection or modification, including any augmentation to the distribution network.

**Access Arrangements**

Rule 5.5 also interacts with the offer to connect phase and relates to the access arrangements entered into between DNSPs and generators/market network service providers. The negotiation framework set out in Rule 5.5 requires a DNSP to use reasonable endeavours to provide the access arrangement being sought by an applicant. This Rule also sets out the information to be exchanged between parties and imposes an obligation on both parties to negotiate in good faith to reach agreement on the quantum of the connection service charge where the connection assets are constructed by the DNSP and any other charges to be paid in relation to augmentations or extensions.

Figure 3.1 provides an overview of the steps that must be followed within these six phases and highlights the interaction between the DNSP and the applicant, the time lines and the information exchanges required within each phase. This diagram also sets out the interaction between Rule 5.3 and the pricing and prudential requirement provisions within the NER.
Figure 3.1: Rule 5.3 - Connection application framework

Connection Enquiry: Applicant makes enquiry with local DNSP specifying type of plant, magnitude and timing of proposed connection. DNSP must acknowledge receipt of enquiry within up to 10 business days. DNSP must inform applicant if information provided is inadequate and advise of additional information required which is of the kind specified in Schedule 5.4.

Response to Connection Enquiry: DNSP must provide in writing to applicant the names of transmission and distribution services providers who must be involved in the connection planning and whether any agreements will be made. DNSP must provide timing and program for connection that can be agreed upon by both parties.

Application for Connection: Applicant submits application to connect and submits all information required in 5.3.3. DNSP must respond within 20 business days. If information is inadequate, DNSP must advise applicant in writing. If summary level of information is inadequate, DNSP must provide written advice of additional technical information necessary to process application. Information to the Applicant in accordance with Schedule 5.4.

Preparation of Offer to Connect: Offer to connect must be made within the time set out in preliminary timeline although additional time may be allowed if access standards have been negotiated. Offer to connect must specify the automatic access standard or negotiated access standard for each technical requirement. Offer to connect must include performance standards.

Finalisation: Offer to connect must be accepted, rejected or altered by申请人. If accepted, the automatic access standard or negotiated access standard for each technical requirement must be met. Connection agreement includes details of connection point, metering arrangements, standards of reliability at the connection point and connection service charges. Schedule 5.6 includes the basis for determining distribution charges under Chapter 6 and prudential requirements in 6.7.

Prudential Requirements 6.21-6.22

Connection Charges 6.21-6.22
3.1.1.3. Analysis of the connection application framework

It is immediately apparent from a review of Figure 3.1 that the current connection application framework is prescriptive, complex and requires intensive negotiation. Some of this complexity and prescription arises because the framework was designed to apply to a range of alternative users with varying technical requirements. Having a single framework that can be utilised by a range of alternative users is a positive feature of the existing arrangements, and in our view should be retained in a national framework.

The framework in its current form has a number of other beneficial features including:

- provisions that require both the DNSP and applicant to exchange information, thereby minimising any information asymmetry that may exist between the parties;
- provisions that require the DNSP to respond within specified timeframes, which prevent the DNSP from unduly delaying the connection application process;
- the specification of the minimum content for a connection agreement;
- the specification of uniform technical requirements to apply across the network; and
- the requirement that NEMMCO be involved in any negotiations relating to technical requirements, and as an active advisory role within this process.

However, these beneficial features are somewhat overshadowed by the complexity that surrounds the interaction of the various negotiation stages specified within the framework. For example, a DG seeking to negotiate access standards faces three distinct negotiation stages, ie, when negotiating technical terms in the application to connect phase, when negotiating price and other terms and conditions of connection in the offer to connect phase and when negotiating its access arrangement under Rule 5.5. While these are set down in the NER as three separate negotiation stages there is a tendency to negotiate all aspects together. The inclusion of separate negotiation stages in the alternative phases appears somewhat artificial. A single overarching negotiation framework would allow these negotiation stages to be formally combined. Moreover, the duplication that currently exists in the NER in relation to the manner by which negotiations should be undertaken in each of these phases could be eliminated.

In reviewing the process surrounding the negotiated access standards, it is unclear why the rules require a DNSP formally to accept or reject the proposed access standard and why provision is then made for the applicant to accept, reject or alter the proposed negotiated access standard. While one would expect the two parties to discuss these issues, there is no obvious need for this level of prescription to be incorporated into the NER. It should simply be sufficient to say that the negotiated access standards that are agreed between the parties must:

- be no less onerous than the minimum access standard contained in the relevant schedules in Chapter 5;
- not adversely affect power system security;
- not adversely affect the quality of supply for other users; and
- comply with any advice provided by NEMMCO.
Another perceived shortcoming of the current process is that although Rule 5.3 can be used by a user seeking to modify an existing connection or plant, it is unclear whether the DNSP and user would have to negotiate on all terms and conditions or just a subset of those terms and conditions pertaining to the modification. For example, if a large load customer wanted to alter an access standard and this modification had no flow on effects (i.e., the existing connection and extension assets do not have to be modified) then there would be no need to reopen all other aspects of the connection agreement. This shortcoming could be addressed in the national framework by incorporating a mechanism within the NER and the connection agreements that allows the existing connection agreement to be amended in circumstances where both parties agree to changes in non-price terms and conditions (including technical conditions which may require NEMMCO involvement) and where those changes have no associated cost effects.

Finally, it would appear that provisions relating to the connection process do not currently require the DNSP to commit to a date by which the connection will be affected (energisation) once the connection agreement is finalised. This is an area that should be addressed in any revised framework by requiring the DNSP to specify the date by which connection will be affected. The ability of a DNSP to commit to a particular date by which connection will be affected will depend on whether the DNSP is to construct the connection assets. Where the DNSP is to construct the connection assets it should be able to develop a timetable for the construction of the connection assets and to identify the date by which connection will be affected (i.e., energising the connection). In circumstances where another party is to construct the connection assets the DNSP should be able to specify the date of connection by reference to the completion of the construction of the connection assets (i.e., connection will be affected within five days of the connection assets being completed).

3.1.2. Jurisdictional arrangements

The obligation of a DNSP to connect a user and the manner by which a small user, large user, micro, small and medium DG’s connection is affected is governed by a myriad of legislative and regulatory instruments in each of the NEM jurisdictions (see Appendix A to Appendix F for a detailed review of these legislative and regulatory instruments). Although these jurisdictional arrangements differ in their scope, application and level of prescription there are a number of common features which are relevant to consider in the context of developing a national framework for distribution network connection. Of particular relevance to this consideration are the jurisdictional provisions relating to:

- the obligation of a local DNSP to connect users to the distribution network;
- the connection application processes available to alternative users; and
- the manner by which any dispute arising from the connection process is resolved.

3.1.2.1. Obligation to connect

A common feature of all the jurisdictional arrangements is the obligation imposed (either expressly or impliedly) upon local DNSPs to connect customers to the network. This obligation is generally subject to the customer’s connection requirements not unreasonably interfering with the connection or supply of other users and meeting specified technical conditions. In some jurisdictions the obligation to connect a customer may also be limited if
the customer fails to meet minimum prudential requirements or fails to pay for the costs of connection which may include the cost of upstream augmentation.

In some jurisdictions separate technical conditions have been developed for the connection of DGs and the obligation of a DNSP to connect is conditional upon these conditions being met.

3.1.2.2. Connection framework

The jurisdictional arrangements currently provide for the use of both standard and negotiated connection contracts.

3.1.2.2.1. Standard connection contracts

Standard connection contracts are typically used by load customers with standard connection requirements.

In some jurisdictions the terms and conditions of the standard contracts are set out in the relevant regulatory instrument (Queensland and South Australia (for load customers only)) while in other jurisdictions the DNSP is responsible for developing standard contracts which must then be approved by the regulator (the Australian Capital Territory, South Australia (for DGs only) and Victoria). In New South Wales DNSPs are required to develop standard contracts that are consistent with the Electricity Act 1995, however, they do not have to have the contracts approved by a regulator.

3.1.2.2.2. Negotiated connection contracts

Negotiated connection contracts tend to be used by load customers with non-standard connection requirements and DGs.

In contrast to the level of prescription contained in the NER the jurisdictional arrangements provide very little guidance on the manner by which negotiations should be undertaken when a user seeks to negotiate its connection requirements. For instance:

- in Victoria the ESC’s Electricity Industry Guideline Number 5 simply states that negotiated terms must be agreeable to both parties. For DGs there are specific provisions contained in the ESC’s Electricity Industry Guideline Number 15 which require a DNSP to negotiate in good faith with the DG. Provisions within this guideline also require the DNSP to provide the DG with reasonable information to enable the DG to assess the commercial significance of the arrangements;

- in New South Wales there are no express provisions requiring the contract to be negotiated in good faith or for the terms to be reasonable but the contract must comply with conditions imposed on the DNSP by its license and cannot be inconsistent with any provisions of the Electricity Act 1995 or regulations;

- in Queensland the Electricity Act 1994 simply states that the DNSP must connect a customer on fair and reasonable terms;

- in South Australia a distinction is drawn between load and DGs and a further distinction drawn based on the size of these customers. In relation to load customers, the Electricity Distribution Code states that for large load customers the terms must be agreed between the parties while for small load customers the terms must be approved by ESCOSA. In
relation to DGs the Electricity Distribution Code states that the agreed terms and conditions must be fair and reasonable for both small and large DGs, however, the terms for small DGs must also be approved by ESCOSA; and

in the Australian Capital Territory there are no express provisions requiring the contract to be negotiated in good faith or for the terms to be reasonable. However, the contract will be unenforceable if the terms are inconsistent with the conditions of the DNSP’s licence or the requirements set out in the Utilities Act 2000, industry or technical codes.

3.1.2.3. Dispute resolution

The dispute resolution mechanisms in place within each jurisdiction vary markedly. For instance, in Victoria and South Australia a condition of the DNSP’s license is that it develop a dispute resolution mechanism that is then approved by the regulator. In Queensland separate dispute resolution mechanisms apply to disputes surrounding a DNSP’s failure to meet an obligation under the relevant Act and disputes surrounding the terms and conditions of connection. In New South Wales alternative dispute resolution mechanisms may apply to standard and negotiated contracts. In Tasmania disputes may be directed to either the regulator or the Energy Ombudsman depending on the nature of the dispute. In the Australian Capital Territory disputes surrounding a DNSP’s failure to meet an obligation specified in the Utilities Act 2000 (which includes the obligation to provide a connection service in accordance with the standard customer contract) must be filed with the Essential Services Consumer Council. It is unclear from the drafting of these dispute resolution provisions whether this dispute resolution mechanism also applies to negotiated contracts.

3.1.2.4. Analysis of the jurisdictional arrangements

Allowing for the use of standard connection contracts is a key advantage of the prevailing jurisdictional arrangements over the NER. The inclusion of standard contracts within the connection application process implicitly recognises the administrative costs that would be incurred if each connection were to be individually negotiated. The use of a standard connection contract that has been approved by the regulator also ensures that any imbalance in the bargaining power possessed by the user and DNSP does not affect the terms and conditions upon which the connection services are supplied. Provision should therefore be made in the national framework for standard connection contracts.

The jurisdictional arrangements relating to negotiated connection contracts provide very little clarity on the manner by which negotiations should be undertaken, the obligations of the parties, the information to be exchanged or the time lines to be adhered to. The absence of this clarity is in direct contrast to the NER and is a clear shortcoming of the current jurisdictional arrangements which means that users are afforded very little additional protection in their negotiations with the DNSP.

The lack of clarity surrounding the dispute resolution provisions in some jurisdictions has the potential to create uncertainty amongst users which is exacerbated when different dispute resolution provisions relate to different users or different contract times. This is another shortcoming of some of the jurisdictional arrangements that should be addressed in a national framework.
3.1.3. Recent reviews of the connection process

Over the last two years Gilbert + Tobin and NERA, the Utility Regulators’ Forum and AAR have undertaken reviews of the connection processes pertaining to retail customers and DGs and have made a number of recommendations that are relevant to our review. An overview of these recommendations is set out below.

3.1.3.1. Gilbert + Tobin and NERA - Public Consultation on a National Framework for Energy Distribution and Retail Regulation

In May 2005 Gilbert + Tobin and NERA published their proposed ‘best practice’ approach to the regulation of energy distribution and retailing.

One recommendation of the review was that the NEL should impose an obligation on a designated distributor to provide standard connection services within designated regions. The standard connection service would encompass the physical connection of premises within a designated distance from an existing network. It was recommended that the AEMC should be required to make rules that would both define the standard connection service (with the definition corresponding to services subject to price regulation) and establish the standard terms and conditions.

3.1.3.2. The Utility Regulators’ Forum – CoPEG

In February 2006, the Utility Regulators’ Forum Embedded Generation Working Group released a Draft CoPEG for consultation. The draft CoPEG was designed to supplement the NER in relation to micro, small and medium DGs but to be subordinate to the NER and existing jurisdictional arrangements. Within this context the following definitions were used to distinguish between micro, small, medium and large DGs:

- **micro DG** - 2kW or AS4777 compliant and connected to the low voltage network;
- **small DG** - greater than 2kW but less than 1MW and connected to the low voltage network but not compliant with AS4777;
- **medium DG** - greater than 1MW but less than 5MW or not greater than 1MW but connected to the high voltage network; and
- **large DG** - greater than 5MW.

Within the draft CoPEG a distinction was drawn between the connection process that should apply to micro DGs and that applying to small, medium and large generators. This distinction appears to have been based on the recognition that the administrative costs associated with negotiating connection contracts for all micro DGs would be substantial and thus a standard contract should be used in these circumstances.

The specific recommendations in this regard were that the DNSP would be accorded responsibility for developing and publishing a standard connection agreement and connection application form which contained the commercial and technical responsibilities of the parties, the charges to apply and the basis for those charges. It was further recommended that the

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DNSP be required to issue a connection offer and a standard connection agreement within twenty days of receiving a completed standard application form.

The draft CoPEG also made a number of recommendations regarding the connection application process for small, medium and large DGs which were assumed to follow the connection application process set out in Rule 5.3. These recommendations included:

- allowing for the development of standard connection agreements for each type of DG;
- providing further clarification on the time frames to apply in the offer to connect and finalisation phases by requiring:
  - a DNSP to use reasonable endeavours to issue the connection offer as soon as practicable following the receipt of a complete connection application and no later than three months after receiving the application; and
  - the connection offer to remain valid and open for acceptance for a minimum period of two months from the day of receipt.

The draft CoPEG contained a number of other recommendations relating to the publication of material by the DNSP including technical requirements for micro, small and medium DGs, commercial arrangements, policies and procedures for connection of an DG and, where appropriate, their standard charges.

A number of submissions were received in relation to the draft CoPEG, which were summarised in CRA International’s “Review of NEM Arrangements for Renewable and Distributed Generation”. The principal concerns raised in these responses related to:

- the unit size definitions used to classify DGs;
- the information requirements with Energy Networks Association claiming that provisions relating to this imposed a significant information burden on DNSPs; and
- the drafting of the Code, with Climate Action Network Australia claiming that the drafting should use binding terminology to ensure greater clarity, certainty and uniformity.

Figure 3.2 sets out the connection application process that would be followed by micro DGs and all other DGs if the recommendations contained within the draft CoPEG were to be adopted in the NER and the NEL.
Figure 3.2: Connection process for DGs

<table>
<thead>
<tr>
<th>Small, Medium and Large DGs – Negotiated Connection</th>
<th>Micro DG – Standard Connection</th>
</tr>
</thead>
<tbody>
<tr>
<td>DNSPs obligation to connect</td>
<td>DNSPs obligation to connect</td>
</tr>
<tr>
<td>Small, medium and large embedded generators make query with DNSP.</td>
<td>Micro embedded generator submits standard connection application form developed by DNSP and preliminary discussions held with DNSP</td>
</tr>
<tr>
<td>Preliminary discussions held with DNSP.</td>
<td>up to 5 business days</td>
</tr>
<tr>
<td>up to 10 business days</td>
<td>up to 5 business days</td>
</tr>
<tr>
<td>DNSP must inform micro embedded generator if additional information required.</td>
<td>DNSP must inform micro embedded generator if information provided is inadequate and advise of additional information required.</td>
</tr>
<tr>
<td>Embedded generators submit complete connection enquiry.</td>
<td>up to 20 business days</td>
</tr>
<tr>
<td>up to 10 business days</td>
<td>DNSP must issue a connection offer and a standard connection agreement.</td>
</tr>
<tr>
<td>DNSP must inform micro embedded generator if another DNSP is more suitable, if a network study is required and the cost of the study, identity of other parties that will be involved and if any works are contestable.</td>
<td>Micro embedded generator submits complete standard connection application form.</td>
</tr>
<tr>
<td>DNSP advises embedded generator of minimum access standards, plant standards and automatic access standards.</td>
<td>up to 20 business days</td>
</tr>
<tr>
<td>DNSP to use reasonable endeavours to publish standard technical requirements for small and medium embedded generators.</td>
<td>Micro embedded generator accepts standard connection agreement.</td>
</tr>
<tr>
<td>Embedded generators submit complete connection application form and where possible use standard connection applications developed by DNSP.</td>
<td>up to 2 months</td>
</tr>
<tr>
<td>time specified in preliminary programme up to maximum 3 months</td>
<td>Agreement Finalised.</td>
</tr>
<tr>
<td>DNSP must issue a connection offer and a connection agreement.</td>
<td>up to 2 months.</td>
</tr>
<tr>
<td>up to 2 months</td>
<td>Embedded Generator accepts connection offer.</td>
</tr>
<tr>
<td>Offer to Connect</td>
<td>Agreement Finalised.</td>
</tr>
<tr>
<td>Finalisation</td>
<td></td>
</tr>
</tbody>
</table>

3.1.3.3. Retail Policy Working Group – Consultation Paper

In June 2007 AAR released a consultation paper which examined a DNSP’s obligation to provide connection services and the interface between DNSPs, users, retailers and DGs. This examination involved reviewing the existing jurisdictional arrangements and prior reviews of these issues and was undertaken with a view to identifying the areas where the current regulatory provisions in the NER required further development.
One area which the consultation paper identified as requiring further development was the connection application process currently applying to retail customers. A number of recommendations were made in relation to this issue including that:

- the NEL impose an obligation on local DNSPs to provide distribution services, in accordance with the NER, in respect of a retail customer’s premises;

- the NER specify:
  - the connection application procedure that would allow an application for connection to be made either by a customer or its retailer;
  - the connection requirements and conditions that must be met before a DNSP is required to connect the customer including the requirement for the customer to pay for dedicated connection assets, any augmentation, extension or other capital works to the distribution system if required to effect connection, compliance with technical and safety requirements in relation to the customer’s installation or equipment and provision of safe and unhindered access to meters and other equipment of the DNSP on the customer’s premises;
  - the DNSP information requirements which would include a requirement for the DNSP to provide a customer with the approved standard terms and conditions (deemed distribution contract) applicable to that customer and notice of the customer’s right to negotiate different terms; and
  - the time frames to apply to ‘standard’ new connections and energisations.

The AAR Consultation Paper also contained a number of recommendations relating to deemed distribution contracts but noted that the deemed distribution contract provisions did not affect the rights of customers to negotiate for the direct provision of distribution services in accordance with Chapter 5 of the NER. Although customers would have the right to negotiate, the alternative arrangements would need to be agreed by both parties and if agreement could not be reached then the default position would apply. AAR noted that this would allow for mutually acceptable deviations from the default model but would not imply any new form of regulatory intervention to supervise such negotiations. It was further recommended that the NER provide protection for small customers negotiating distribution contracts including protected terms and cooling off periods.

The terms and conditions contained within the deemed distribution contract would, under the proposed framework, be based on model terms (to be specified in the NER) although a DNSP could propose variations to these terms to reflect its customer service standards, network performance standards and any specific characteristics of the network. Within this framework, the AER would be responsible for approving the DNSP’s proposed deemed distribution contract as part of the DNSP’s revenue determination approval process. Once approved, the contract would become a standard deemed distribution contract that the DNSP is required to adopt and publish.

AAR also referred to the possibility for deemed contracts to be developed for large customers, or classes of large customers, and submitted to the AER for approval. According to the consultation paper the terms and conditions of these deemed contracts would have to pass a ‘fair and reasonable’ test to be approved by the AER.
AAR also recognised the work undertaken by the Utility Regulators’ Forum in relation to DGs and concurred that the existing provisions relating to network connection procedures and negotiation frameworks in the NER (and in particular their application to smaller DGs) should be enhanced. AAR concluded that to the extent that the MCE wished to adopt all or part of the modified form of the draft CoPEG, the Code should be reformulated as rules.

### Conclusion on recommendations

There are a number of positive recommendations flowing from the work that has been undertaken by AAR on behalf of the Retail Policy Working Group and the Utility Regulators’ Forum.

The most notable of these recommendations is that standard contracts be developed for small retail customers, micro DGs and any other classes of customers that have standard connection requirements. It is well recognised that where a user has standard connection requirements there are considerable administrative costs to be saved from utilising standard connection contracts rather than requiring each individual to negotiate their connection requirements. Accordingly there is some benefit to incorporating standard connection contracts that have been vetted by the AER within the national framework in circumstances where users’ connection requirements can be sufficiently standardised. We also agree with AAR’s recommendation that the Rules specify the connection requirements that must be met before a DNSP is required to connect a customer.

In relation to the provisions contained in the draft CoPEG we also acknowledge the lack of uniform technical requirements for small and medium generators across the jurisdictions. If the national framework is to apply to these generators then uniform technical requirements must be developed and referenced in the framework in the same manner as the technical requirements for large generators are currently referenced in Schedule 5.2. Defining the appropriate technical requirements and size of embedded generator proponents is beyond the scope of this paper and should be subject to further consultation.

The draft CoPEG’s recommendation to require DNSPs to issue a standard connection offer within a defined period of time after receiving a standard application form is also an important factor to incorporate within a national framework. The draft CoPEG allowed DNSPs 20 business days to issue such an offer. While it may appear that issuing a standard connection offer should involve only minimal administrative work on the part of DNSPs, the DNSP will need this time to consider the cost of constructing any connection assets and/or extension assets required by the micro DGs. We do not have a definitive view on the time that this process should take and thus this issue could be considered in further consultation.

The draft CoPEG’s recommendation to impose an expiry date on both a standard and negotiated offer to connect should, in our opinion, also be incorporated in a national framework. Imposing an expiry date on the offer will afford the DNSP some protection particularly in circumstances where the offer to connect contains a proposed cost of constructing the connection assets and/or extension assets necessary to affect connection. Since the cost of constructing these assets will change over time it will be necessary to impose an expiry date on a connection offer issued by a DNSP. In the draft CoPEG it was recommended that DGs have a two month period to accept either a standard or negotiated connection offer. This appears to be an appropriate length of time although the DNSP should be able to extend this period if it elects to do so.
The draft CoPEG also recommended that DNSPs have up to three months to develop an offer to connect once a completed application form is received. This period of time may not be appropriate for alternative classes of users with varying connection requirements and thus the time period for developing an offer should be specified in the DNSP’s negotiation framework and be approved by the AER.

3.2. Proposed national framework for distribution network connection

Based on the observations from the preceding section and the recommendations contained in the three recent reviews it is clear that there would be some benefit from developing a national connection application framework that is sufficiently flexible to accommodate the varying connection requirements of users and that meets the following objectives:

- is not unduly complex or prescriptive;
- contains the technical provisions necessary to ensure the safe and reliable operation of the power system;
- recognises the administrative costs associated with negotiating connection and, where possible, provides users with the option of utilising either a standard connection application process or a negotiated connection application process;
- minimises any imbalance in the bargaining power that may otherwise exist between a user and DNSP negotiating a connection application by:
  - clearly setting out the obligations of both parties;
  - establishing a single common negotiation framework to be used when negotiating the terms and conditions of connection (including price, non-price and technical terms) that amongst other things require:
    - the DNSP and user to negotiate in good faith;
    - the DNSP to use its reasonable endeavours to provide the user with the connection services sought by the user;
    - the DNSP and user to exchange technical and commercial information that the other party may reasonably require to enable them to engage in effective negotiation;
    - the DNSP to adhere to well defined time limits within the negotiation process and the connection enquiry phase;
  - providing sufficient protection for vulnerable users;
  - ensuring that users have access to a cost-effective dispute resolution mechanism in the event that agreement cannot be reached; and
  - recognises the emerging contestable nature of constructing connection assets.

These objectives have formed the foundation for the development of the proposed national connection application framework set out in Figure 3.3. A number of specific recommendations contained in the draft CoPEG have also been used to develop the connection application framework and are referred to explicitly in the recommendations where relevant.
Figure 3.3: Proposed framework

**Standard Connection Service Route**

- **Connection Enquiry**
  - Applicant (or retailer acting on behalf of Applicant) makes enquiry with local DNSP specifying connection

- **Response to Connection Enquiry**
  - DNSP informs Applicant of any standard connection services that would encompass its connection requirements.
  - If there is a standard connection service then the DNSP must inform Applicant that they have a choice to either use the standard connection service or to negotiate their connection requirements.
  - The DNSP must provide Applicant with the standard application form.
  - At this time the DNSP must also:
    - provide the Applicant with a copy of the negotiation framework that will apply if a negotiated connection service is sought;
    - inform the Applicant if any aspects of the service are contestable; and
    - inform applicant of additional information required which is of the kind specified in Schedule 5.4.

- **Development of Offer**
  - Applicant submits additional information requested by the DNSP.

- **Finalisation**
  - Applicant (or retailer acting on behalf of Applicant) submits completed Standard application form.

If additional information is required, the applicant may submit it to the DNSP, and the DNSP must ensure that it is provided to the Applicant in accordance with Schedules in Chapter 5.

- **Negotiated Connection**
  - Applicant (or retailer acting on behalf of Applicant) advises DNSP it will be seeking connection using either:
    - DNSP responsible for connection points and NEMMCO advised if necessary.
Negotiated access standards

Connection charges may be levied if DNSP provides connection assets and the charge will depend on whether the provision of these assets is a direct control service or a negotiated distribution service:

- **Direct control service**
  - If a direct control service then connection charge will be regulated by a revenue cap, price cap or a combination of the two and will not be negotiated. (6.2.5)

- **Negotiated distribution service**
  - If a negotiated distribution service then any negotiated connection charge must comply with the pricing principles set out in 6.7.1.

Prudential Requirements 6.21-6.22

Rule 6.21 - 6.21.1

DNSP may require an applicant establish prudential requirements which may require payment of financial capital contributions, non-cash asset contributions, distribution service charge prepayments, guaranteed minimum distribution service charges or quantities for an agreed period or financial guarantees. Connection agreement may include provisions for refunding all or part of payments within a specified time frame.

Rule 6.22

Capital contribution, prepayment or financial guarantees may cover future revenue related to the provision of direct control service for any dedicated connection or extension assets installed as part of a new connection or modification.

Any payment be reflected in revenue related to the provision of direct control services.
The proposed national connection application framework consists of four phases (the connection enquiry phase, the response to connection enquiry phase, the development of offer phase and the finalisation phase) and two alternative connection application routes (standard connection service and negotiated connection service). Before moving on to examine the manner by which this connection application framework will operate it is important to address a number of structural features that are assumed to provide the foundation for the proposed framework.

3.2.1. Structural features

The framework set out in Figure 3.3 assumes that:

β a local DNSP has an obligation to connect users in its designated distribution area;
β the framework can be applied to all users other than small retail load customers irrespective of their technical requirements;
β provisions are in place to facilitate the development of standard contracts;
β the negotiation process is streamlined; and
β there is a cost-effective dispute resolution mechanism in place that can be accessed by all users.

3.2.1.1. Obligation to connect

The proposed structure assumes that DNSPs will be obliged to review and process any connection applications received (as it is currently required to do under Rule 5.2.3(d)) and to provide the connection service on terms and conditions of access that are consistent with the requirements of Chapters 4, 5, 6 and 7 of the NER (as it is now required to do under the Draft Rule 6.1.4(2)) subject to the user meeting a number of defined connection requirements. These defined connection requirements and conditions will be of a similar nature to those identified by AAR and will include the requirement for the user:

β to pay the DNSP for the construction of any dedicated connection assets (where the construction of these assets is not contestable) and any extension works to the distribution system required to effect the connection; and
β to comply with technical and safety requirements in relation to the customer’s installation or equipment, ie, payment for extension assets, dedicated connection assets and compliance with technical and safety matters.

Recommendation 10.

Specify in the Rules the connection requirements that must be met by a user which include the requirement for users to:

β pay the DNSP for the construction of any dedicated connection assets (where the construction of these assets is not contestable) and any extension works to the distribution system required to effect the connection; and
comply with technical and safety requirements in relation to the customer’s installation or equipment, ie, payment for extension assets, dedicated connection assets and compliance with technical and safety matters.

3.2.1.2. Technical requirements

To ensure the framework is sufficiently flexible to apply to all users, the requirements of small load (excluding small retail customers), large load, micro, small and medium DGs must be included in the NER in schedules similar to those devised for large DGs, market network service providers and market customers. The information requirement schedules (schedules 5.4 to 5.6) should also be revised to reflect these additional users.

Recommendation 11.

Schedules to Chapter 5 of the NER should be amended to include a definition of the technical requirements for small load, large load, micro, small and medium DGs.

3.2.1.3. Standard connection contracts

The standard connection application route will not be available in all circumstances. Rather, the standard connection service route will only be available in circumstances where:

- a user’s connection requirements can be standardised; and
- there are a sufficient number of users with these requirements to warrant the development of a standard connection contract and application form.

The standard connection application route will allow the recommendations contained in the draft CoPEG in relation to the standardised connection of micro DGs to be integrated into a revised Rule 5.3. Over time it may be possible for additional standard connection services to be defined in the NER through the rule change process where the principles set out above are met. In these circumstances the NER should require a DNSP to develop and publish a standard contract and application form for these additionally defined standard connection services and to have these approved by the AER.

To enable the standard connection route to be utilised by particular users it will be necessary:

- to define the standard connection service to apply to particular users which will initially only require defining the connection services to apply to micro DGs;
- to require DNSPs to develop and publish standard contracts and application forms for these specified connection services; and
- to require the AER to approve the standard contracts and application forms developed by the DNSP.

Recommendation 12.

The NER should define the standard connection services to apply to micro DGs.
**Minimum content for standard applications**

This minimum content for application forms should be specified as a schedule to Chapter 5 and will likely include the information currently contained in Schedule 5.4 (Information to be Provided with Preliminary Enquiry) although some additions may be made to reflect differences in information requirements for alternative customers. The standard application forms should also specify both the length of time it will take for the standard connection to be completed and the time it will take to process the application. This period of time should be fair and reasonable and be approved by the AER.

**Recommendation 13.**

The NER should set out the minimum content for standard applications in a schedule to Chapter 5.

**Minimum content for standard contracts**

The minimum content for standard contracts should be specified in the Rules and would likely include those items currently contained in Schedule 5.6 although the content of this schedule may have to be modified to reflect differences in customer types. The minimum content provisions should include a provision requiring DNSPs to specify the date by which connection will be effected (energising) by reference to the date on which the connection agreement is finalised, i.e., within five days of connection agreement being finalised. In keeping with AAR’s recommendations, when considering the terms and conditions within these standard contracts the AER should apply the ‘fair and reasonable’ test when determining whether to approve the proposed standard contracts.

It is envisaged that the standard contracts will also specify connection charges (including the cost of constructing the connection assets and any extension assets) which will be recovered directly from the user. Any charges payable by the user for the constructing of connection or extension assets should be specified in the standard contract. Since these charges may change over time it will be necessary to impose an expiry date on the standard offer. In the draft CoPEG it was recommended that micro DGs have a two month period to accept the standard connection offer. This appears to be an appropriate length of time although the DNSP should be able to extend this period if it elects to do so.

**Recommendation 14.**

The NER should:

- set out the minimum content for standard connection contracts in a schedule to Chapter 5 including a requirement for the DNSP to specify the number of days after the finalisation of the agreement that the standard connection will be effected;

- require the AER to approve the content of the standard application form and the terms and conditions specified in the standard contract and require the AER to apply the ‘fair and reasonable’ test when determining whether to approve the proposed standard contracts.
3.2.1.4. Streamlining the negotiation process

Provisions within Rule 5.3 currently provide for the negotiation of technical access standards during the application for connection phase while the negotiation of connection charges, prudential requirements and any other terms and conditions occurs during the offer to connect phase. Although one would reasonably expect the technical access standards to be defined before determining the price and other connection terms and conditions, the distinction created by the inclusion of separate negotiation stages in the alternative phases is somewhat artificial.

Removing this artificial distinction would allow the DNSP and user to negotiate technical access standards, connection charges (where relevant), prudential requirements and any other terms and conditions simultaneously in accordance with a regulator approved DNSP specific negotiation framework.

Provisions in the Draft Chapter 6 rules currently provide for the development of a DNSP-specific negotiation framework that, once approved by the AER, will apply to any negotiations pertaining to the Negotiated Distribution Service. Rule 6.7.5(c) sets out the minimum provisions that must be incorporated within the negotiation framework which includes the following:

The negotiating framework for a Distribution Network Service Provider must specify:

(1) a requirement for the provider and a Service Applicant to negotiate in good faith the terms and conditions of access to a negotiated distribution service; and
(2) a requirement for the provider to provide all such commercial information a Service Applicant may reasonably require to enable that applicant to engage in effective negotiation with the provider for the provision of the negotiated distribution service, including the cost information described in subparagraph (3); and
(3) a requirement for the provider:
   (i) to identify and inform a Service Applicant of the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the negotiated distribution service; and
   (ii) demonstrate to a Service Applicant that the charges for providing the negotiated distribution service reflect those costs and/or the cost increment or decrement (as appropriate); and
(4) a requirement for a Service Applicant to provide all such commercial information the provider may reasonably require to enable the provider to engage in effective negotiation with that applicant for the provision of the negotiated distribution service; and
(5) a requirement that negotiations with a Service Applicant for the provision of the negotiated distribution service be commenced and finalised within specified periods and a requirement that each party to the negotiations must make reasonable endeavours to adhere to the specified time limits; and
(6) a process for dispute resolution which provides that all disputes as to the terms and conditions of access for the provision of negotiated distribution services are to be dealt with in accordance with the relevant provisions of the Law for dispute resolution; and
(7) the arrangements for payment by a Service Applicant of the provider’s reasonable direct expenses incurred in processing the application to provide the negotiated distribution service; and
(8) a requirement that the Distribution Network Service Provider determine the potential impact on other Distribution Network Users of the provision of the negotiated distribution service; and
(9) a requirement that the Distribution Network Service Provider must notify and consult with any affected Distribution Network Users and ensure that the provision of negotiated distribution services does not result in non-compliance with obligations in relation to other Distribution Network Users under the Rules.

This framework clearly defines the rights and obligations of both parties and addresses a number of the factors cited above that will be critical to ensuring any imbalance in the bargaining power between a user and a DNSP are minimised. Specifically, the framework imposes an obligation on both parties to negotiate in good faith and requires the obligations of both parties (as they relate to information exchange and the requirement to adhere to time lines) to be clearly defined.

It is envisaged that this framework could also be applied to the connection process once some modifications are made to reflect existing requirements in the NER. In this context it is worth noting that there may be some concerns surrounding the use of the negotiation framework for the connection process as opposed to specifying the explicitly negotiation requirements in the Rules. Specifically, there may be some concern that the use of a DNSP-specific negotiation framework may result in a loss of national consistency in the manner by which connection agreements are negotiated. While there may be such concerns it should be recalled that the provisions in Rule 5.3 relating to negotiations are relatively general in nature (ie, Rule 5.3.6 (f) simply requires the DNSP and applicant to negotiate in good faith) and thus it is unclear whether there could be any loss of national consistency by moving from the current arrangements to utilising the negotiation framework in Draft Rule 6.7.5. This is an issue that could be considered further in the consultation which is to follow this report.

Our recommended modifications to Draft Rule 6.7.5 are set out below.

Recommendation 15.

The NER should state that the negotiation framework developed in accordance with Draft Rule 6.7.5 and as modified should apply in the negotiated connection application process.

Rule 6.7.5(c) should be modified to include the following additional provisions which would require the DNSP to specify:

- a requirement for the exchange of technical as well as commercial information between the two parties;
- a requirement that when considering a connection application the DNSP is to use its reasonable endeavours to provide the user with the service it requires in accordance with the reasonable requirements of the user, including without limitation, the location of the proposed connection point and the level and standard of power transfer capability that the network will provide (currently Rule 5.3.6(d));
- any offer pertaining to a negotiated distribution service to be fair and reasonable and consistent with the safe and reliable operation of the power system in
accordance with the NER and consistent with the technical requirement schedules contained in Chapter 5 (as applicable) and must not impose conditions on the user that are more onerous than those contemplated in these technical schedules (currently Rule 5.3.6(c));

- the cooling off period that will apply to any contract negotiated with vulnerable users;

- a requirement that when considering a connection application the DNSP must consult with any affected Distribution Network Users and NEMMCO (where relevant) if the DNSP believes, in its reasonable opinion, that compliance with the terms and conditions of those connection agreements will be affected, in order to assess the application to connect and determine:
  - the technical requirements for the equipment to be connected;
  - the extent and cost of augmentations and changes to all affected networks;
  - any consequent change in network service charges; and
  - any possible material effect of this new connection on the network power transfer capability including that of other networks (currently Rule 5.3.5(d)); and

- the time periods for the commencement and finalisation of negotiations relating to negotiated connections once a completed application form is submitted to the DNSP for the alternative types of users and connection requirements.

One implications of this recommendation is that for some DNSPs the negotiating framework would cover some services which are regulated as direct controlled services because the terms and conditions for those services are not pre-determined by the application of other rules or instruments.

The first of the bullet points list above is not a specific connection process requirement. Negotiation of other types of services may also require the two parties to exchange technical information and thus it is recommended that this be addressed before the Draft Chapter 6 Rules are finalised. This could be done by expanding both Draft Rule 6.7.5(c)(2) and (4).

The final bullet point in this list of recommendations will in part address the issue raised in the draft CoPEG that an offer to connect should be provided as soon as practicable after receiving a complete application and no later than three months after receiving the application. Since the negotiations may differ in their intensity across alternative classes of users with alternative connection requirements the time frames should be flexible and defined within the negotiation framework which the AER must then assess for reasonableness.

Adopting this modified Rule 6.7.5 and requiring all negotiations to be undertaken in accordance with this framework would allow a number of the provisions currently in Rule 5.3 to be removed from the NER, ie, provisions relating to the requirement to negotiate in good faith, the obligation to exchange information and requirement to adhere to specified time
frames. This framework could also be referenced in Rule 5.5 and a number of similar provisions removed.

The minimum content of the negotiated connection contract should also be specified in the NER. Schedule 5.6 is currently used for this purpose in the NER, however, some amendments should be made to this schedule to ensure that it can be utilised in contracts negotiated with small and large load customers, micro, small and medium DGs. Schedule 5.6 should also include a provision requiring DNSPs to specify the timetable for the construction of the connection assets where it is to undertake this work. In addition schedule 5.6 should specify the date by which connection will be effected (i.e., energising) by reference to the date that the construction of connection assets is completed.

Recommendation 16.

Schedule 5.6 of the NER should be amended:

- to ensure that it can be utilised in contracts negotiated with small users, large users, micro, small and medium DGs;
- to include a cooling off period for those contracts negotiated with small users; and
- to include provisions which enable the connection agreement to be modified over time where both parties agree to changes in non-price terms and conditions (including technical conditions which may require NEMMCO involvement) and where those changes have no associated cost effects.

3.2.1.5. Dispute resolution mechanism

The dispute resolution mechanism applying to the connection process was recently revised as part of the review of Chapter 6 of the NER. In accordance with Part M of the Draft Rules the AER will act as arbiter of any disputes relating to price and non-price terms and conditions of connection. This mechanism will ensure that the smaller and less experienced distribution users will be able to access a cost-effective dispute resolution mechanism and is therefore appropriate.

3.2.2. Operation of the proposed connection application framework

As mentioned previously the proposed framework consists of four phases and provides for the use of either a negotiated connection service contract or, where relevant, a standard connection service contract. A user’s decision to use either one of these alternatives will only flow once the connection enquiry is made and it is informed of the availability of a standard connection service. The provisions contained in the connection enquiry phase are therefore common to the two alternative connection application processes. The remainder of this section sets out the proposed operation of the connection enquiry phase and the paths that would be followed by users opting (where possible) to use the standard connection service application process or the negotiated connection service application process.

3.2.2.1. Connection enquiry phase

The connection enquiry phase in the proposed framework broadly follows that currently specified in Rule 5.3.2 although additional obligations would be imposed on the DNSP which relate to informing the user of:
the availability of standard connection services;
the contestability of any aspect of the connection service sought by the user;
the negotiation framework that will apply if the negotiated connection application route is followed; and
the indicative value of the loss factor applying in the area within which the user is seeking connection which will be based on estimates set out in the planning report (see section 2.3.1.1).

**Recommendation 17.**
The NER should require a DNSP, within five business days of receiving a user’s initial enquiry:

- to advise the user whether there is a standard connection service that would encompass its connection requirements and if so:
  - supply the user with the relevant standard contract and application form; and
  - inform the user that they have the option of using either the standard connection service or negotiating an alternative connection service.
- to provide the user with a copy of the negotiation framework it has developed in accordance with Rule 6.7.5 and that has been approved by the AER which will come into operation if the connection service is to be negotiated;
- to inform the user of whether any aspects of the connection service are contestable;
- to inform the user of any additional information required which is of the kind specified in Schedules 5.4; and
- to inform the user of the indicative value of the loss factor applying in the area within which the user is seeking connection.

If a standard connection service is available then the user should be required to advise the DNSP whether it will be seeking connection via the standard connection service route or the negotiated connection service route. At this stage the framework splits into the standard connection application and the negotiated connection application route. These two alternative routes are examined in turn below.

**Recommendation 18.**
The NER should require a user in the connection enquiry phase to advise the DNSP whether it will be seeking connection via the standard connection service route or the negotiated connection service route.
3.2.2.2. Standard connection application

3.2.2.2.1. Connection enquiry

Recommendation 19.

The NER should state that where a user selects the standard connection application route the DNSP must:

- advise the user as soon as practicable, and no later than five business days after receiving advice from the user that it will be seeking the standard connection service route, if the application should be processed by another DNSP; and

- within five business days provide the user with any technical information necessary to process the application in accordance with the technical schedules in Chapter 5 to the extent that it holds such information.

3.2.2.2.2. Response to connection enquiry

If the user advises the DNSP that it will be submitting a standard connection application then the DNSP will not be required to respond formally to the connection enquiry and the parties will move on to the development of offer phase.

3.2.2.2.3. Development of offer

The development of offer phase will be triggered once the DNSP receives a completed standard application form from the user.

As noted in section 3.1.3.4 the draft CoPEG allowed DNSPs 20 business days to issue an offer once the standard application form had been received from the user. We do not have a definitive view on the time that this process should take and for the purpose of this recommendation have utilised the 20 business day time period. However, we note that this issue could be considered in the consultation that will follow this report.

Recommendation 20.

The NER should require the DNSP to issue a connection offer and a standard connection agreement within twenty business days of receiving a completed standard application form.

3.2.2.2.4. Finalisation

Once the user receives the connection offer and standard connection agreement it will have up to two months to accept the offer. After this time the offer will expire (unless otherwise agreed by the DNSP). Where required by NEMMCO the connection agreement should be jointly forwarded by the user and the DNSP.

Recommendation 21.

The NER should allow a user (utilising the standard connection application route) two months to accept the offer otherwise the offer should be deemed to have lapsed unless the DNSP agrees to extend the offer.
3.2.2.3. Negotiated connection application

3.2.2.3.1. Connection enquiry

Recommendation 22.

The NER should state that where an application is for a negotiated connection service the DNSP must within ten days:

- advise the user if the application should be processed by another DNSP; and
- provide the user with any technical information necessary to process the application in accordance with the technical schedules in Chapter 5 to the extent that it holds such information.

3.2.2.3.2. Response to connection enquiry

The procedure set out in the existing Rule 5.3.3 should be followed during this phase.

3.2.2.3.3. Development of offer

The development of offer phase represents the most significant departure from the current arrangements contained in Rule 5.3. Under the proposed framework the DNSP will be required to commence negotiations with the user once it receives an application to connect that contains all of the information specified by the DNSP in the response to connection enquiry phase (and where relevant the application fee). It is proposed that the NER require both the DNSP and the user to negotiate the terms and conditions of connection (including access standards, connection charges (where appropriate), prudential requirements and any other non-price terms and conditions) in good faith in accordance with the approved negotiation framework developed under Rule 6.7.5.

The negotiation of access standards will be subject to the provisions contained in 5.3.4A(a)-(d), ie, any negotiations relating to access standards must:

- be no less onerous than the minimum access standard contained in the relevant schedules in Chapter 5;
- not adversely affect power system security;
- not adversely affect the quality of supply for other users; and
- involve NEMMCO in an advisory capacity and accor NEMMCO twenty business days to inform the parties in writing of any advisory matters arising as a result of the proposed negotiated access standard.

Whether or not the parties can negotiate connection charges will depend on whether the construction of connection assets (including both dedicated connection assets and extension assets) are defined as a direct control service or a negotiated distribution service. If the services are deemed to be a direct control service then the connection charge will be regulated by a revenue cap, price cap or a combination of the two and the DNSP will be required to inform the user of those charges. If the services are determined to be a negotiated distribution service then the agreed charge must comply with the pricing principles set out in
Rule 6.7.1. These issues should be clarified in the national framework. The costs that should be reflected in the connection charges are considered in Chapter 4 of this report.

Any negotiation regarding prudential requirements must also comply with NER 6.21 and 6.22. Once the negotiations are complete then an offer to connect will be developed by the DNSP which contains the information specified in Schedule 5.6 and specifies the outcome of any negotiation relating to access standards, connection charges, prudential requirements and any other terms and conditions. This offer will be provided to the user within the time specified in the preliminary program or later if the access standards have been negotiated.

Recommendation 23.

The NER should:

β combine the technical, price and non-price negotiation phases currently set out in the application for connection and offer to connect phases;

β remove any provisions which will be captured in the negotiation framework specified in Rule 6.7.5;

β require the DNSP to commence negotiations with the user as soon as it submits a completed application form; and

β require both the DNSP and user to negotiate in good faith

β state that any negotiation relating to access standards must:

– be no less onerous than the minimum access standard contained in the relevant schedules in Chapter 5;

– not adversely affect power system security;

– not adversely affect the quality of supply for other users; and

– involve NEMMCO in an advisory capacity and accord NEMMCO twenty business days to inform the parties in writing of any advisory matters arising as a result of the proposed negotiated access standard.

β require the DNSP to develop an offer to connect which contains the information specified in Schedule 5.6 and specifies the outcome of any negotiation relating to access standards, connection charges, prudential requirements and any other terms and conditions within the time specified in the preliminary program or later if the access standards have been negotiated.

3.2.2.3.4. Finalisation phase

Once the user receives the connection offer and standard connection agreement it will have up to two months to accept the offer. After this time the offer will expire unless otherwise agreed by both parties. Where required by NEMMCO, the connection agreement should be jointly forwarded by the user and the DNSP.
Recommendation 24.

The NER should allow the user (utilising the negotiated connection application route) two months to accept the offer otherwise the offer should be deemed to have lapsed unless the DNSP agrees to extend the offer.

3.3. Consistency with National Electricity Market objective

In developing the proposed framework for connection application, we have been mindful to ensure that the framework promotes the NEM objective, as set out in section 7 of the NEL. In our view, the NEM objective is promoted through the development of a framework that minimises the costs associated with accessing distribution networks, whilst maintaining system security and reliability. The proposed framework promotes the NEM objective by:

- clarifying and simplifying the process for applying for connection to a distribution network, particularly for small load, micro, medium and large DGs;
- providing certainty as to the minimum technical standards that must be satisfied by micro, medium and large embedded generations, through their incorporation in the NER;
- providing a single negotiation framework for both price and non-price terms and conditions of connection, which will allow for tradeoffs between price and non-price terms and conditions to be negotiated;
- improving the flexibility of the negotiating framework for connection applications, by allowing a DNSP to develop the framework, subject to requirements in the NER, rather than prescribing the framework directly in the NER; and
- providing standard connection agreements for small load customers and micro DGs, with the option to negotiate the agreement if required.

All of these elements of the proposed framework will, in our view promote the NEM objective.

3.4. Implications and transitional issues

Apart from the proposed amendments to the negotiation framework and the explicit recognition of micro, small and medium the content of the proposed national framework does not differ substantially from the arrangements currently in place in the NEM jurisdictions. The transitional issues will therefore largely flow from the specific licensing arrangements in place.
4. A national framework for connection charges

Charges for new connections and capital works contributions are another aspect of the connection process that we have been asked to examine, with a view to providing advice on the development of a new national framework.

In considering this issue we have sought:

- to clarify the terminology used and in particular have sought to provide a clear definition of the term connection asset charges;
- to review the current approach to determining connection charges in the NER and in each of the NEM jurisdictions;
- to develop a national framework for connection charges that can be applied to all users;
- to ensure that the national framework promotes the NEM objective; and
- to develop recommendations for amendments to the NER to implement the proposed framework and to set out any transitional issues.

The remainder of this chapter considers these issues in greater detail.

4.1. Terminology

The terms connection charges and capital contributions vary widely in their meaning across the jurisdictions and so it is important at the outset to set out the terminology that we will adopt in this report. To avoid confusion this report will draw no distinction between capital contributions and connection charges. Instead the term connection cost will be assumed to refer to all costs arising directly from, and attributable to, the connection of a new network user as a connection cost, and the associated charge to the connection applicant as the connection charge.

We are aware that the term connection cost may be used to describe both the costs associated with the provision of connection assets (connection asset charges) and the costs associated with the ongoing operation and maintenance of those connection assets. For the purpose of this report the focus is on connection asset charges.

We have also drawn a distinction between the types of assets that connection asset charges may be levied. Specifically, we have drawn a distinction between:

- Dedicated connection assets which are those assets installed solely for the purpose of the connecting user and which are expected to remain for the sole use of the connecting user at all times over the life of the assets, ie, construction of the physical line between a customer and the nearest available shared network (either a low voltage or feeder

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25 For example, in the NERA and Gilbert +Tobin Consultation paper, capital contributions referred only to upstream augmentation to the shared network, and not any direct costs associated with a customer’s connection. These direct costs were referred to as connection charges. In some jurisdictions however, the term capital contributions is also sometimes used when referring to both direct costs and upstream augmentation costs.
distribution network) and modifications to the low voltage or feeder network at the
physical point of connection to accommodate the new customer;

- Extension assets, which are those assets installed to lengthen or otherwise extend the existing distribution system to facilitate the connection. These assets may commence their lives as dedicated assets (ie, linking one user only to the network) but later become shared as additional users connect to the network via the extension asset; and

- Shared network assets are those assets that constitute the shared network.

This distinction is in keeping with the terminology used in the draft CoPEG.

Connection asset costs are any one-off cost that would not have been incurred, but for the new connection, and that are dedicated to the use of the connection applicant. Using the definitions set out above connection asset costs would encompass both dedicated connection assets and extension assets but would not include any costs arising from the augmentation of the shared network.

The distinction between dedicated and shared assets means that it is important to define the point at which an asset is dedicated to the provision of connection to the new user, as opposed to assets that are shared amongst all network users. The definition of this point currently varies between each jurisdiction.

As noted above, extension assets may commence their lives as a dedicated asset but later become a shared asset as other users utilise the extension asset. In these circumstances, some mechanism for compensating the original customer who provided the original asset is usually applied.

The dedicated connection asset requirements and associated costs are likely to vary between customer types, particularly between load and embedded generation, in line with their particular connection needs and technical requirements. These technical requirements ensure that electricity system security and reliability are maintained, and drive decisions about the assets needed to connect a new user to the network.

Finally, and as outlined above, connection asset charges are those levied by a DNSP to recover the costs of assets associated with a new connection. In some jurisdictions, the provision of some of these connection assets is contestable, such that there would be no scope for a DNSP to charge for those assets, in the absence of a separate agreement to construct the asset by the connecting user and the DNSP. The connection application process requires that a new connection applicant be informed where a service is contestable, and this can impact on any subsequent charges levied.

The potential for the provision of connection assets to be contestable raises the issue of whether there is a need to consider requirements in the NER to address the potential competitive advantage that incumbent DNSPs might possess in the provision of contestable connection assets. Whilst this concern may arise in theory, it is not clear whether in practice incumbent DNSPs in jurisdictions where connection asset provision is contestable have been receiving a competitive advantage.

Box 4.1 provides a summary of the terminology used in the remainder of this chapter.
Box 4.1: Terminology

Connection costs are the costs arising directly from, and attributable to, the connection of a new network user as a connection cost, and the associated charge to the connection applicant as the connection charge.

Connection asset costs are any one-off cost that would not have been incurred, but for the new connection, and that are dedicated to the use of the connection applicant.

Dedicated connection assets are those assets installed solely for the purpose of the connecting user and which are expected to remain for the sole use of the connecting user at all times over the life of the assets.

Extension assets are those assets installed to lengthen or otherwise extend the existing distribution system to facilitate the connection. These assets may commence their lives as dedicated assets (i.e., linking one user only to the network) but later become shared as additional users connect to the network via the extension asset.

Shared network assets are those assets that constitute the shared network.

4.2. Current approach to connection asset charges in the NEM

The current connection charging arrangements prevailing in each jurisdiction notionally seek to recover the connection costs associated with a new customer. In practice however, there are considerable differences in:

- the definitions of connection costs used and, in particular, whether and if so how much of, the costs associated with augmenting the shared network assets should be recovered from the connection applicant; and
- the policy approach adopted in each jurisdiction which influences the methodologies used to calculate connection charges for alternative customer types within and across each jurisdiction. 26 These policy approaches appear to be designed to balance the incentives for efficient investment in connection assets against concerns associated with equity and fairness.

In this section we outline the differences as they relate to the following characteristics:

- the basis of charges;
- the refund mechanisms; and
- the form of regulation applied.

Before discussing each of these elements, we outline the requirements in Chapter 5 and the Draft Chapter 6 of the NER as they relate to connection asset charges (or capital contributions).

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26 For example, the approach to connection charging and capital contributions for embedded generators in New South Wales is different from the charging methodology applied to rural customers seeking connection to the distribution network.
4.2.1. Connection asset charges in the Chapter 5 and Draft Chapter 6 of the NER

Connection service charges and capital contributions are referenced in three separate areas in Chapter 5 and the Draft Chapter 6 NER.

The first reference is contained in Rule 5.3.6(h) which states that an offer to connect must define the basis for determining distribution service charges in accordance with Chapter 6, including the prudential requirements.

The term distribution services is defined in Chapter 10 of the NER as being any service associated with the conveyance of electricity through the distribution system including entry services, exit services and use of system services. An entry service is a connection service provided to generators and is formally defined as

A service provided to serve a generator or a group of generators, or a network service provider, at a single connection point.

An exit service is a connection service provided to load customers and is formally defined as

A service provided to serve a transmission customer or distribution customer or a group of transmission customers or distribution customers, or a network service provider or a group of network service providers, at a single connection point.

In practice entry and exit service charges often encompass both charges for the provision of connection assets and operation and maintenance charge for those assets. The charges relating to the provision of connection assets may be recovered through a one-off charge, or an ongoing payment supported by some form of financial guarantee.27

These entry and exit charges are usually only levied on generators and in some instances large loads, although in principle the NER would allow for them also to be levied on small customers. The arrangements for recovering the costs of connecting small customers are, however, usually governed by jurisdictional arrangements that vary considerably between jurisdictions, and differ from the approach allowed in the NER. These arrangements are examined in the following section.

The form of regulation applying to entry and exit charges will, under the Draft Rule 6.2.1, depend on whether the AER defines the services as a direct control service or a negotiated distribution service. In defining these services the AER is to have regard to, amongst other things, the form of regulation factors as developed by the Expert Panel, in its report to the MCE on the development of a nationally consistent regulation of energy services.28 In some jurisdictions, the provision of connection assets is treated as contestable (see section 2.2.4 below for a detailed discussion of the current jurisdictional arrangements).

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27 The Rules relating to financial guarantees are provided in Draft Rule 6.21.1.
Assuming however that the provision of connection assets is classified as a negotiable service, in keeping with the AEMC’s conclusion in relation to transmission, then the relevant charge will reflect the technical specifications and requirements in chapter 5, and be based on the negotiating framework provided for in draft Chapter 6, Part D.

The second reference to connection service charges and capital contributions is contained in the access arrangement provisions in Rule 5.5 (with which an offer to connect must conform). In accordance with Rule 5.5(f)(1) the DNSP and connecting generators or market network service providers must negotiate in good faith the connection service charge to be paid by the generator or market network service provider in relation to connection assets to be provided by the DNSP. Rule 5.5(f)(3) further requires the parties to negotiate in good faith to reach agreement on the user of system charges to be paid in relation to any augmentations or extensions required to be undertaken on all affected transmission and distribution networks. An important point to note about these provisions is that its drafting presumes that the provision of connection assets is a negotiable service, however, in keeping with Draft Rule 6.2.1 such a decision would have to be made by the AER.

The third reference made to connection service charges and capital contributions is contained in the prudential requirement provisions contained in Draft Rules 6.21-6.22. These provisions state that a DNSP may require a DG or a distribution customer that requires a new connection (or modification in service for an existing connection) to establish prudential requirements. These prudential requirements may be met in a number of ways but of particular interest in this context are the financial and non-cash capital contributions. In accordance with Draft Rule 6.22.1(b) a DNSP may recover a capital contribution up to the provider’s future revenue related to the provision of direct control services for any new assets installed as part of a new connection or modification to an existing connection, including any augmentation to the distribution network.

These prudential requirement provisions also state that a connection agreement may set out the conditions under which, and the time frame within which future users of the distribution network contribute to refunding all or part of the payments recovered from the connecting user (Draft Rule 6.21.1(c)(1)). This provides an opportunity for a DNSP or connection applicant to negotiate a mechanism for the refunding of all or part of the charge for the provision of connection assets, in the event they become used by another distribution network user.

4.2.2. Basis for connection charges across the NEM jurisdictions

Charges for the provision of connection assets are based primarily on the cost of providing connection assets. To determine the charge, it is therefore necessary to consider what is considered to be a connection asset for the purposes of calculating the associated charge in each jurisdiction.

The approaches used in each jurisdiction vary according to whether there is a standard infrastructure service provided at no additional charge, with requirements in addition to the standard infrastructure charged at cost, through to charging entirely for the service. There are

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29 AEMC, Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18, November 2006, pg. 36.
also differences in approach associated with the inclusion of extension assets, dedicated assets and shared assets in the charging cost base. In the remainder of this section we outline the approached used in each jurisdiction.

4.2.2.1. Australian Capital Territory

The basis for calculating the relevant capital contribution charge is provided in the Electricity Network Capital Contributions Code (2001). The Code allows a DNSP to impose a capital contribution charge upon a user for the development or augmentation of the network (section 3.1) if:

- the requirements of the user exceed the basic standard infrastructure, which the DNSP must install at no charge. The capital contribution charge payable by the customer must not exceed the additional costs incurred by the DNSP in providing the alternative infrastructure (section 3.3);
- the customer is a rural customer in which case a DNSP may requirement the payment of a capital contribution equal to the difference between the costs incurred in connecting the rural customer and the average cost of connecting a residential customer in an urban area (section 3.4); and
- the load is uneconomic such that the over the life of the additional network assets required to connect the user the costs would exceed the network revenue received from that user. The capital contribution in this case may be set at the full cost of the work (section 3.5).

The basic standard infrastructure includes: the construction of extension assets from the existing boundary to the land being developed; the provision of a service connection up to a maximum of 22 metres from the distribution system to the premises if overhead assets or 8 metres if underground assets. The Code, and therefore the basic standard infrastructure, is based on the provision of connection assets in relation to load, because there have been no connections associated with generation. Current arrangements are unclear in terms of the relevant charge payable for a DG seeking connection to the distribution network.

4.2.2.2. New South Wales

In New South Wales the basis for determining the relevant provision of connection asset charge is governed by IPART’s Capital Contributions Determination 2002.\(^\text{30}\) The Determination requires that a customer pay for the direct costs of establishing the connection up to a defined point of connection to the network.\(^\text{31}\) The direct costs are those associated with providing and installing lines and equipment dedicated to the connecting customer. IPART explicitly excludes the recovery of any augmentations to the shared network arising from the connection to be charged to the connecting customer.

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\(^{30}\) Independent Pricing and Regulatory Tribunal, Capital Contributions and Repayments For Connections to Electricity Distribution Networks in New South Wales, 2002.

\(^{31}\) This point has been defined by IPART as the point on the network at which the use of assets changes from shared among customers generally to dedicated to one or more customers.
This approach requires the definition of the associated connection point, which IPART defines as the point at which the use of the asset changes from being dedicated to the connecting customer, to being shared amongst more than one customer.

While the above is the general approach for customers connecting to the network, the basis for charging for connection of rural and large load customers differs. For these customers, a DNSP is entitled to recover some of the augmentation costs associated with providing electricity services.

4.2.2.3. Queensland

In Queensland, the basis for charging for the provision of connection assets differs according to four customer types. These are standard asset customers (SAC), connection asset customers (CAC), embedded generators (EG) and individually calculated customers (ICC). A SAC is defined as any customer using less than 4 GWh annually; a connection asset customer between 4 and 40 GWh annually; and an individually calculated customer over 40 GWh annually.

For a SAC the basis of the connection asset charge is the average cost of connection assets for all standard asset customers. To the extent that a SAC’s cost of connection (including a contribution toward shared network assets) exceeds the average, the DNSP may require an additional capital contribution.

The basis of connection asset charges for CACs, EGs and ICCS is the cost of the dedicated connection assets. However, the Electricity Regulation (2006) allows a DNSP to refuse connection unless a connection customer contributes towards the costs of providing dedicated assets, extending the network, or augmenting the existing network to increase its capacity. In general, these charges are a site specific network charge, but a party is able to negotiate a one-off payment in place of an ongoing charge.

4.2.2.4. South Australia

Chapter 3 of the Electricity Distribution Code sets out procedures for establishing new or modifying existing connections that require augmentations or extensions. It provides that a DNSP is allowed to charge for such connections provided that the offer is based on the most efficient and technically feasible solution.

The basis for the charge, as specified in clause 3.5 of the Code is:

- the cost of dedicated connection assets;
- the cost of any required extension to the existing network;
- an allocation of augmentation costs to the capacity of the existing network; and
- any reimbursement to contributions from other upstream customers.

To determine the actual connection and extension costs, a tender process is required to be undertaken.
The allocation of augmentation costs is based on a formula specified in clause 3.6.4 of the Electricity Distribution Code, and relates to the expected new customers’ demand multiplied by a unit augmentation cost reflecting the average cost of augmenting the network as determined by ESCOSA. Where a connection results in a need to accelerate augmentation to the network, then the charge is based on the actual allocated costs of the additional augmentation required.

For a DG, sections 2.5, 2.6 and 2.7 of the Code note that pricing for connection, extension and augmentation charges must be calculated as an excluded service charge as mentioned above and be in accordance with ESCOSA guidelines (sections 2.5 and 2.6) or Chapter 5 of the National Electricity Code (section 2.7). Notably, section 2.7 (a) provides that a DNSP must not charge a small DG for any augmentation required as a result of the connection of their units to the distribution network.

Finally, while the above provides the basis for costs, the Code also provides a rebate (clause 3.7), which is $3,000 for residential customers, and for non-residential customers the higher of $3,000 or $1,200 plus three times the increase in DUOS charges.

4.2.2.5. Tasmania

In Tasmania there are no specific regulatory provisions relating to connection charges. Aurora Energy has, however, published a procedure, entitled ‘Overhead Electricity Supply at Low Voltage” which sets out its approach to connection charges and capital contributions.

In relation to connection, Aurora Energy provides subsidies for service connection, transformer installation and the extension of a high or low voltage asset along a public road. The value of these subsidies is set out in Attachment 1 of the procedure and ranges from $430-$6,400 for service connections, $5,100-$21,800 for transformer installations and $7,500 for extensions along a public road.

Where a user’s requirements deviate from the standard criteria (ie, when Aurora is required to convert its line from a 1 to a 3-phase) the user bears the cost of these differences. Aurora’s procedure also requires the user to pay all Aurora’s costs in obtaining an easement that is located on another party’s property. Developers are also required to pay any additional costs above the subsidies including a capital contribution towards a development main.

4.2.2.6. Victoria

The approach to charging for connection to the distribution network in Victoria is broken into two components. The first relates to the recovery of the cost of dedicated assets associated directly with the connection, although these services are treated as contestable. The provision of these dedicated assets, including any lines or otherwise, are treated as an excluded service for the purposes of the determination of prices.

The second relates to the recovery of any new works or augmentations to the existing network arising from a new connection. The approach is governed by clause 3 of Guideline 14 – Provision of Services by Electricity Distributors. The Guideline allows for the charging of the incremental costs associated with a new customer connection, less the incremental revenue expected to be earned from the connection of the new customer. In this way, a new connecting customer will pay a contribution to network augmentation where it results in
augmentations above expectations in the distribution network, as contemplated by existing distribution network charges as determined by the ESC.

For DGs, the basis for connection service charges is that of a shallow connection. This is defined in Guideline 15 – Connection of Embedded Generators, as any connection assets up to the first transformation within the distribution system. As for load customers described above, a DG can also be charged for the cost of dedicated assets to enable connection to the distribution network.

4.2.3. Repayment mechanisms

In some jurisdictions there are repayment mechanisms where extensions to the existing network are charged to an initial connecting customer, but are subsequently shared with other users. In general, these schemes are in place where these costs are borne by the initial connecting customer, but are limited to a period of years following the building of the initial extension asset.

The mechanisms used in each state are summarised in table 2.1 below.

<table>
<thead>
<tr>
<th>Jurisdictional approaches to repayment mechanisms</th>
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<tbody>
<tr>
<td>New South Wales</td>
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<tr>
<td>Is there a reimbursement scheme?</td>
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<tr>
<td>Period over which reimbursement can occur</td>
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<tr>
<td>Applicable customer types</td>
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<td>Basis for sharing</td>
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<tr>
<td>South Australia</td>
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<tr>
<td>Is there a reimbursement scheme?</td>
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<tr>
<td>Period over which reimbursement can occur</td>
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<tr>
<td>Applicable customer types</td>
</tr>
<tr>
<td>Basis for sharing</td>
</tr>
</tbody>
</table>

4.2.4. Contestability in the provision of connection assets

Many of the state jurisdictions have deemed the provision of connection assets as a contestable service, thereby allowing a connection applicant to seek alternative providers for connection assets from the relevant DNSP. The jurisdictions where the provision of connection assets is contestable include: New South Wales; South Australia; Tasmania, and Victoria.
4.2.5. Conclusion on jurisdictional arrangements

Based on the foregoing it is clear that the manner by which connection charges are calculated varies markedly across each jurisdiction. These jurisdictional differences have arisen as a result of inconsistencies in the:

- definition of costs used that can be recovered through connection charges;
- definition of a ‘standard connection’, where a connection charge is only levied if the connection exceeds standard specifications;
- scope for recovery of dedicated asset costs that are subsequently shared;
- connection point for distinguishing between shared and dedicated assets; and
- methodologies for calculating connection charges for small customers, large loads and embedded generation.

Importantly, when the current jurisdictional approaches are considered in detail, it is not clear whether they would all satisfy the NEM objective, particularly where they distort locational pricing signals provided to new connection applicants.

4.3. Consideration of connection charges in recent reviews

4.3.1. Gilbert+Tobin and NERA - Public consultation on a national framework for energy distribution and retail regulation

The Gilbert+Tobin and NERA Consultation Paper also considered issues relating to connection charges and capital contributions. Of particular relevance to this consideration were the recommendations made in relation to standard connection services and capital contributions for shared network augmentation. In relation to standard connection services the report stated that standard connection services which are based on the physical connection of premises within a designated distance should be free, ie, the cost should be recovered through DUOS charges. Under this proposal customers would only be responsible for paying the direct costs of connection where their requirements exceed those specified in the standard connection service. Consideration was also given to the potential for extension assets later to become shared assets and the authors concluded that a share of the direct costs of connection should be refunded at a later date if other customers connect within a specified time period.

In relation to capital contributions for shared network augmentation the authors drew a distinction between small customers and large customers and DGs. For small customers, the authors concluded that they should not be required to make any capital contribution for shared network augmentation. In reaching this conclusion the authors made the following observation:

For small customers, there is no economic justification for seeking a capital contribution to cover the cost of upstream augmentation. If incremental network augmentation is required as a result of new small customers joining the network and the cost of this augmentation is not already covered by current tariffs, this implies that the current network charge for that area is below the true long run marginal cost (LRMC) for that area. If charges did reflect
LRMC, then the cost of incremental augmentation would already be factored into the charges being paid by all customers.\(^\text{32}\)

For large customers and DGs the authors concluded that they should pay a capital contribution which would reflect the additional costs imposed on the system as a result of the connection. Once again the authors considered that to the extent that these assets later became shared then a share of those costs should be refunded.

The authors further recommended that:

- the NER set out the permitted basis for charges including an obligation on DNSPs to connect customers at least cost (unless otherwise agreed with the customer); and
- the AER develop a Connections and Capital Contribution Statement of Requirements setting out the methodology to be applied by DNSPs when calculating connection charges and capital contributions.

### 4.3.2. The Utility Regulators’ Forum – draft CoPEG

The draft CoPEG also contained provisions relating to connection charges. Specifically, the draft CoPEG states that the DNSP shall be entitled to levy a fair and reasonable charge for connection and integration to the network. The connection and integration costs referred to in the draft CoPEG include the costs of constructing or upgrading dedicated connection assets, the costs of constructing any extension assets from the existing shared network and network augmentation costs.

In a submission made to the MCE, the Climate Action Network Australia stated that provisions relating to connection and integration costs penalised proponents of DGs by expecting them to pay for any distribution network augmentation (deep connection costs) while large established generators were only required to pay the costs of assets directly required by the new connection (shallow connection costs). This apparent imbalance has been addressed from a transmission perspective in AEMC’s revised transmission rules.

### 4.3.3. Retail Policy Working Group – Consultation Paper

AAR’s Consultation Paper also made reference to connection charges. In this regard AAR recommended that a ‘standard’ customer connection be developed and the costs associated with this ‘standard’ connection service be recovered through the DNSP’s distribution price determination. For connections that require connection assets in excess of the ‘standard’ or require the network to be augmented or extended, AAR has recommended that small retail customers pay these additional costs directly to the DNSP.

### 4.4. Principles for a new national connection charging framework

As outlined in section 4.2.2 the manner by which connection charges are calculated varies markedly across each jurisdiction. Our focus in developing a new national framework for connection charges has therefore been:

to clarify the definition of connection asset charges and assets that currently vary across each of the jurisdictions (see terminology in Box 4.1 that is assumed to underpin the proposed framework);

- to develop specific connection charge pricing principles that provide incentives for efficient investment in the expansion of, and connection to, the distribution network;

- to develop a methodology for determining efficient connection charges; and

- to ensure that the NEM objective is satisfied.

To ensure an appropriate transition to this new framework, we also make recommendations about how to transition between existing jurisdictional arrangements and the proposed national framework.

### 4.4.1. Pricing principles

Economic efficiency requires that prices reflect, wherever practicable, the marginal costs of providing a good or service. By charging the marginal cost for providing the good or service, the user will consider whether consuming the good or utilising the service will produce benefits that outweigh the associated cost. This results in an efficient level of demand for the good or service and the efficient allocation of resources throughout the economy.

These economic efficiency principles also apply when considering the relevant costs to include in a charge payable by a connection applicant, to promote efficient investment in connection assets and expansions to the network. The marginal costs associated with a new connection would include all of the costs that are incurred due to the connection and are likely to vary according to the connection location. The marginal costs associated with a new connection will therefore reflect factors such as:

- the distance from the nearest low or high voltage network;

- the capacity required; and

- specific features of the network at the connection location.

Finally, marginal cost pricing is a forward looking concept, meaning that any costs associated with assets already constructed are considered to be sunk. Given that their inclusion in connection charges may affect a decision to connect to the network at a particular location, they should be excluded from the calculation of marginal cost.

Following the logic outlined above, one might argue that it would be efficient to price all services provided by a distribution business at marginal cost. However, because distribution services require investment in assets with significant fixed costs, such a strategy would not provide a DNSP with sufficient revenue to recover its investment cost, nor earn an appropriate return for the risks borne. It is usual in these circumstances to recover the revenue needed to maintain the financial viability of the DNSP through fixed charges, ideally levied on those users who are not likely to change their use of distribution services on the basis of charges that exceed the marginal cost. Given the essential nature of the common network, it would therefore be most appropriate for the fixed costs to be recovered from all users of the network.
To determine the costs to include in the calculation of connection charges, it is necessary to consider those costs directly attributable to the new connecting customer. The cost of assets that would not have been built but for the new connection should clearly be allocated to the connection applicant entirely. This ensures that a prospective connection applicant will only choose to connect where the benefits of doing so outweigh the costs directly arising from the connection.

Where a connection results in congestion in the distribution network, one might argue that the cost of any subsequent augmentation of the shared network to maintain distribution capabilities should be charged to the new connection applicant. However there is no efficiency reason for charging shared augmentation costs to a connection applicant. This presumes, in the case of an exporting distributed generator that the relevant DNSP can constrain an applicant from exporting energy to the extent it contributes to congestion in the network. In fact, there are good efficiency reasons why a connection applicant should not be charged any shared network augmentation costs arising from a new network connection.

The reasons why augmentation costs of the shared network should not be allocated to a new connection are:

- It is very difficult to attribute the need for actual network augmentation investment to a particular new network connection, and if an ‘in principle’ charge is applied, this cost might not in practice be incurred;
- The need to augment capacity in the shared network can arise from increases in the demand for network capacity from both existing and new users. It is therefore not always straightforward to attribute the need to augment network capacity to new (potentially recovered through a connection charge) as opposed to existing users (recovered through distribution network charges); and
- The most efficient response to a new connection leading to the need for network augmentation might be a reduction in the use of the network by existing users. By allowing the augmentation costs to be borne by all users, efficient use of the network can be achieved.

This suggests that efficiency would be enhanced by both existing users and new users responding to the higher costs arising from network augmentation that might have been caused by a new connection. This conclusion applies irrespective of the connection being for a small retail load customer or a distributed generator. This means that, for the NEM objective to be promoted, connection charges should not include any costs associated with augmentation of the shared network that might arise because of the new connection.

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33 We acknowledge that there are concerns about not recovering shared network augmentation costs from connection applicants, where the need for the augmentation is for a short period of time, for example in response to a mine connection with a limited mine life, such that the augmentation becomes redundant sometime in the future. In our view however, it is still appropriate to share the cost of this augmentation amongst all users because at the time of the connection it may not be clear precisely how long the mine site will operate, nor whether there could be other changes in network demand such that part, if not all, of the shared network augmentation becomes used following the closure of the mine. This approach is equivalent to the cost of augmentation of shared network transmission costs being shared amongst all users, arising from the connection of a mine to the transmission network.
We recognise that this conclusion is contrary to the views expressed in the Gilbert+Tobin Consultation Paper, the AAR Consultation Paper and the draft CoPEG. However, we also note that these previous reviews had not undertaken a detailed consideration of the economic rationale underlying the recovery of network augmentation costs and its application across all users, as well as across the transmission and distribution networks.

This latter point is an issue that was highlighted by Climate Action Network Australia in its response to the draft CoPEG in which it stated that any charging for shared network augmentation to DGs would be inconsistent with competitive neutrality with generators connected to the transmission network. Generators connected to the transmission network are only required to pay the shallow, dedicated connection costs associated with facilitating connection to the transmission network. From a competitive neutrality standpoint it would not be appropriate for DGs to be required to pay for any shared network augmentation that arises.

Of course, there may be instances where a DG (as for a generator connecting to the transmission network) would like improved network transfer capability, and in these circumstances it would be possible to negotiate with a DNSP a payment for improved capabilities with the network provider. However, any improved network capability would be available to all users, irrespective of the funding by the DG (or the transmission network connected generator). This approach is analogous to a generator choosing to pay for transmission network augmentation when the augmentation does not otherwise satisfy the requirements of the regulatory test.

Competitive neutrality between DGs and other forms of generation may also be extended beyond the price terms of connection agreements to the non-price terms. For example, where an unscheduled DG does not opt to fund improved network transfer capability and connects to a point in the shared network subject to a transfer constraint, it will be appropriate (from a neutrality perspective) for the non-price connection terms to include a constraint on the maximum energy exports of the generator. Such constraints will provide a proxy for the NEMMCO constraint algorithm applied to scheduled generators, thereby providing neutrality between these forms of generation.

The obligation on the DNSP should be to connect a load or DG at the point in the network (the connection point) where it is capable of receiving or exporting electricity as required. In some instances this may mean connecting to the high voltage network rather than the closer, lower voltage network. However, this does not mean that there will necessarily be sufficient transfer capability at the connection point at the time of connection to allow the DG to export its entire output at that point. In these circumstances, and in the absence of the DG choosing to fund shared network augmentation, it is appropriate for the DG’s output to be constrained. This has the effect of providing a signal to a connecting DG about the location for its proposed connection.

Finally, marginal cost pricing as a forward looking concept implies that efficiency would not be enhanced by attributing any sunk costs associated with the existing network to a new connecting customer. There is, however, one circumstance where it might be appropriate for costs that might be considered sunk to be recovered. These are costs associated with the construction of extension assets that commence their life as a dedicated asset but later become shared as a result of a new connection.
4.4.1.1. Sharing the cost of extension assets

It is feasible that, when evaluating whether to connect to the shared network, a connection applicant might believe that others are likely to use part of the extension asset at some future time. If there was a mechanism by which the first connection applicant could recover part of the cost of the dedicated asset that became shared, then this would result in efficient connections that would otherwise not have been built being constructed. It also minimises any distortions that might arise as a number of connection applicants delay connecting so as not to be the first applicant to connect, thereby incurring the largest proportion of the cost.

It is necessary, however, to consider an appropriate length of time in which a connection applicant can recover part of the cost of assets that become shared. The length of time should be of sufficient length that it would be reasonable for a connection applicant to have taken the potential for the recovery of costs into consideration when making the initial decision to connect to the network.

4.4.1.2. Summary

In summary, principles for economic efficient provision of connection assets would require that a connecting customer:

§ should not pay for any augmentation of the shared distribution network that might arise from servicing the load/generation output of a newly connected customer;

§ should pay for the dedicated connection assets; and

§ should pay for extension assets where necessary, although it is acknowledged that in some instances a subsequent customer may make use of the extension assets, and therefore it would be appropriate to provide a repayment of part of the cost of the extension to the initial customer. This should occur to the extent that the likelihood that the cost may be shared was taken into consideration by the initial customer in deciding to proceed with the extension construction. For this reason, it would be appropriate to provide a limitation on the period over which a repayment would be made.

It is also important to ensure that the relevant costs included in the connection charge are the efficient cost of providing connection, given the technical requirements and standards. This means that the framework should provide incentives to ensure that DNSPs minimise the cost of providing connection assets.

Recommendation 25.

The NER should allow, subject to a decision by the AER as to the form of regulation to apply to the provision of connection assets, a DNSP to recover from connecting users the cost of dedicated connection assets as well as extension assets for the sole use of a new connection that, but for the new connection, would not have been incurred – a connection asset charge.

Recommendation 26.

The NER should adopt the terminology in Box 4.1 for the purposes of calculating a connection asset charge.
Recommendation 27.

A compulsory connection asset charge should not include the cost of any shared network augmentation that may be required to service the load/generation output arising from a new connection. However, a connection applicant may also choose to fund shared network augmentation by negotiation between the DNSP and the connection applicant.

4.4.2. Methodology for determining efficient connection charges

Applying the principles outlined above, a connection charge should recover the costs of:

- assets required to connect a new customer to the existing network given the technical requirements necessary to maintain system security and reliability, including any extensions to the existing network (extension assets); and
- assets that are dedicated to the use of the new customer (dedicated connection assets).

The result of this approach is that any costs arising from a need to augment the shared network would be recovered through use of system charges applied to all users. This investment would be to maintain system security and reliability in the face of increasing growth in the use of the network. The proposed framework for connection charges would therefore have no impact on the (present value of) the total revenue earned by a network service provider (although it will affect its timing). The proposed framework is consistent with the approach already used in many jurisdictions. For the remaining jurisdictions it will have no impact on the (present value of) total revenue earned by the network service provider, but rather it will affect the share of costs recovered from new connection applicants compared with all users.

4.4.2.1. Approach to connection charges for TNSPs

The approach adopted by the Australian Energy Markets Commission, in its recent review of the rules relating to the economic regulation of electricity transmission services, was to regard connection services, including both entry and exit services, as negotiable services (see Chapter 10 definition of ‘negotiated transmission service’). This means that these charges are negotiated between the connection applicant and the relevant DNSP and both parties have access to binding dispute resolution through a defined negotiation arbitration process.

The AEMC’s recently revised transmission rules require generators to pay only connection costs of the form specified in this paper. With regard to shared network costs, TNSPs may not impose compulsory charges on the connection application, with such costs being either:

- borne by consumers where the expansion of transfer capability satisfies the regulatory test;
- paid for by the connecting generator to the extent that the augmentation does not satisfy the regulatory test (albeit with no firm property right to the resultant additional transfer capacity); or
not incurred because the generator chooses not to fund the non-regulatory test satisfying expansion and instead to take the risk of being constrained in its energy output by means of the applicable NEMMCO network constraint algorithm applied to its generation bids.

4.4.2.2. Approach to connection charges for DNSPs

The approach adopted by the MCE in the development of the initial electricity distribution rules is to allow the AER to determine the relevant form of regulation to apply to each service provided by a DNSP. In so doing the NER require the AER to apply the criteria developed by the Expert Panel – see Draft Rule 6.2.1.

It is likely however that given the approach adopted in each jurisdiction, the AER will consider connection charges as a negotiable service, in a similar way to that provided by the AEMC for transmission connection charges. If this is the case, then the pricing principles contained in Draft Rule 6.7.1 would apply. These pricing principles, coupled with the fact that the connection applicant will have access to the dispute resolution mechanism, mean that there will be some constraint on the DNSP to install connection assets at least cost.

As identified earlier, attainment of the NEM objective requires competitive neutrality in both the price and non-price connection terms afforded to both transmission and distribution connected generators. Incentives for efficient investment between these competing forms of generation necessitate that the rules governing DNSPs:

- allow DNSPs to levy connection charges for any one-off cost that would not have been incurred, but for the new connection, and that are dedicated to the use of the connection applicant;
- do not allow DNSPs to levy compulsory charges for augmentations to the shared network in order to provide enhanced network transfer capability;
- permit connection applicants to negotiate payment for augmentations to the shared network in order to provide enhanced network transfer capability, with no firm rights to such capacity; and
- permit the negotiation of non-price connection terms that ensure system reliability is not unduly affected by connection of unscheduled generation assets to a constrained part of a distribution network.

4.4.2.3. Jurisdictional arrangements for each customer type

The above discussion has not drawn a distinction between the principles and framework applicable to different connection types. The jurisdictional arrangements provide different arrangements for:

- small load customers;
- large load customers; and
- DGs.

In a number of jurisdictions, small load customers are provided with standard connection assets at no additional charge. For large load customers and DGs however, the approach is
usually to charge the site specific costs associated with connection, and in some instances the
cost of shared network augmentations required in the remaining network.

In our view, there may be a justification for the provision of standard connection assets to
small load customers at no additional charge, thereby recovering these costs from all users.
However, it is difficult to provide an economic reason for drawing any distinction in the
framework for connection charges between large load customers and DGs. It is our view that
the same connection charging framework outlined above should be applied to both these
types of connections.

4.4.2.4. Approaches to repayments of connection asset charges

As outlined above, where extension assets that were previously dedicated become shared as a
result of new connections, it is appropriate for the original connecting customer to recover
part of the costs associated with having provided the extension asset. It is therefore necessary
for the development of a mechanism for partially repaying these costs.

Developing such a framework that promotes proper incentives for efficient investment,
however, is not trivial. In developing a repayment framework it is necessary to consider:

β how to ensure that individual negotiation does not lead to inefficient network expansion?
β what is an appropriate length of time in which a connecting customer can be expected to
be reimbursed for part of the previously dedicated costs?
β what sharing mechanism should be applied if the subsequent user’s connection
requirements (ie, size and location along the extension asset) differ from that of the
original connecting party?
β who should be responsible for monitoring the shared costs?; and
β what happens if the connection user assets are transferred during the requisite period?

In addition, there is a need to define the appropriate connection point for the determination of
connection costs as compared with those costs that should be properly attributed to the shared
assets, and thereby all users. The appropriate definition of the connection point is likely to
vary between each DNSP and whether the connection applicant is a large or small load or a
DG. It is therefore appropriate for the connection point to be defined by the AER through the
development of a Guideline under the rules. This will provide sufficient flexibility and scope
for modification, whilst also having legal status under the rules.

In addition, the AER should develop a Guideline under the rules outlining the details of the
repayment mechanism. It is appropriate that this mechanism be developed as a Guideline
rather than being specified in the rules, since it involves the implementation of the connection
charging framework, and is likely to vary through time.34 The rules in this instance should
only provide the framework for the development of the mechanism by the AER.

34 This approach is analogous to the making of the Regulatory Test by the AER, consistent with the framework provided
in the rules.
Finally, in our view, it is appropriate for a connection applicant who has paid for extension assets to recover part of the costs of the extension, if and when other users connect to the extension, for up to seven years from commissioning. This allows a connection applicant considering paying for an extension asset to factor possible repayments into a decision to pay for the construction of the extension asset.

At the expiry of the seven year period, the assets would revert to being treated as part of the shared network. This means that any subsequent new connecting user would no longer be required to contribute to the cost of the extension asset.

An example of the application of the framework for connection charging outlined above is provided in Box 4.2.

**Box 4.2. Example of an application of the connection charging framework**

Consider a distributed generator (DG) seeking to connect to the distribution network within a local suburb. The distributed generator is required to connect to the high voltage network, which is located 5 kilometres from the proposed site for the DG rather than the low voltage network adjacent to the site (as assumed for the purposes of this example to be required by the AER’s connection point guideline). The cost of extending the high voltage network is $5 million, and the cost of subsequently providing a dedicated connection to the newly extended high voltage network is $1 million. Finally, assume that connection has been classified as a negotiable service by the AER.

The $1 million would be treated as a dedicated asset, and charged directly to the DG. The assets required are based on the definition of a connection point provided by the AER for this type of DG. The high voltage network would be extended up to the connection point (again the same as defined by the AER), and charged to the DG.

The DG would therefore be required to pay $6 million in connection asset charges.

Separately, the DNSP had anticipated a need for increased network capability in the area served by both the existing low and high voltage networks at the last regulatory reset, and had successfully included the cost of the augmentation in its revenue allowance. With the connection of the DG, the DNSP undertakes the capital investment to augment the capacity of either or both the existing low and high voltage networks. While the DG connecting is part of the reason for needing an upgrade, the other reason for the upgrade was increased peak load electricity use by residential households due to an increase in the number of air conditioners installed in homes. There was no need for the DNSP to charge the DG for the existing shared network augmentation, as it had been incorporated into the revenue allowance of the DNSP. This means that the DNSP was no worse off from the connection of the DG.

One year after Commissioning, a proposed shopping centre applies for connection to the network, at a location adjacent to the DG. It is also required to connect to a high voltage network, and the appropriate connection point (as defined by the AER) is on the extension asset funded by the contribution from the DG. The shopping centre would therefore pay the dedicated asset costs associated with the connection to the high voltage network, (say $500,000) plus a contribution for the extension asset costs, based on a methodology determined by the AER. The DNSP would collect these funds, and pass them back to the DG.

35 The choice of seven years is somewhat arbitrary, but consistent with the length of time adopted in a number of jurisdictions for similar mechanisms.
4.4.2.5. Conclusion

Recommendation 28.

The NER should require the AER to develop a Guideline for the determination of connection asset charges. The Rules should provide that the Guideline include:

- a definition of a standard small customer connection asset that may vary for each DNSP, for which no connection asset charge may be levied; and
- a definition of the relevant connection point.

Recommendation 29.

The NER should require the AER to develop a Guideline that provides a methodology for the partial repayment of connection asset charges when a new customer connects to an extension asset within 7 years. The Rules should provide that the Guideline include:

- an obligation for a DNSP to provide a repayment to a connection customer in the event a new connection utilises part of the previously dedicated assets;
- dispute resolution procedures;
- the basis for calculating the repayment; and
- a requirement that the asset becomes treated as a shared network asset at the expiry of the seven year period.

Recommendation 30.

Provisions within the NER that currently refer to the recovery of network augmentation costs through a connection charge should be removed (ie, Rule 5.5(f)(3)(i) and Draft Rule 6.22(1)(b)).

4.5. Consistency with the National Electricity Market objective

In our view the framework outlined above provides the basis for promoting the NEM objective. The framework will ensure that:

- a connection applicant is only charged the marginal dedicated costs associated with a connection, ensuring that a decision to connect will only be made when the benefits outweigh the costs;
- any impact on shared network costs arising from a new connection are shared amongst all users, creating price signals for the efficient use of the network, and minimising the occurrence of constraints within the distribution network;
- a DNSP will be financially no worse, nor better off, as the costs arising from a new connection are allocated either to the new connection user, or all users within the network;
provisions are retained for connection applicants to negotiate contributions towards
shared network costs to obtain enhanced network transfer capability, with non-price
connection terms serving as a proxy constraint mechanism where shared network
augmentation is not efficient;

a mechanism is developed to allow for the repayment of part of the costs of any dedicated
asset that subsequently becomes shared, within a defined period of time, eliminating the
scope for distortions in connection timing; and

incentives for efficient provision of connection assets arise through either the direct form
of price control or by connection assets being defined as a negotiable service.

In sum, this will mean that connection charges will provide efficient signals to connection
applicants as to the costs associated with connection to the network. In this way, the NEM
objective will be promoted.

4.6. Implications and transitional issues

The proposed new national framework connection charges is consistent with many of the
approaches currently applied in each of the NEM jurisdictions. For this reason, transitioning
to the new arrangements should be relatively straightforward.

We recommend that for new connection applications, the new national framework would
replace existing arrangements. However, for existing reimbursement schemes, the existing
state jurisdictional arrangements should apply up to the implementation of the new national
scheme.
5. **Network losses**

5.1. **Introduction**

The purpose of this section is to examine whether the treatment of network losses in distribution networks is consistent with providing efficient signal for investment in DG projects. As will be discussed below, one of the important benefits that DG may provide is the alleviation of network losses, particularly in regional areas where losses may be high. Hence, ensuring that losses are treated appropriately can have a material effect on the economics of a DG project.

This section first discusses how we have applied the objective of the NEL to consider this issue, and then discusses how losses generally are treated when dispatching generators and settling the market (i.e. effecting payments to or from the wholesale pool). Our consideration of the current requirements and practice in relation to distribution loss factors then follows.

Anticipating this analysis, we conclude that the treatment of losses in the distribution networks does not reward DG projects appropriately for the losses they alleviate, which arises from the fact that the ‘price’ that is paid (and received) for causing (reducing) losses on the distribution networks reflects the average losses incurred on the network rather than the losses incurred by the marginal unit of consumption (i.e. marginal losses). We then explain how losses calculations could be improved to remove this potential barrier to efficient DG.

5.1.1. **Efficiency and competitive neutrality**

The NEL objective requires the promotion of efficient investment in, and use of, electricity services for the long term interests of users with respect to the price, reliability of supply of those services. Of most relevance to the issues considered in this section, efficiency in the mix of generation would be achieved by selecting the mix that represents the least-cost to society, taking account of the costs of generation, transport and losses that are incurred.

In normal situations, the signal to encourage an efficient production choice is achieved by ensuring that proponents of different production options are faced with the costs and benefits that they cause or generate. In competitive markets, the production options that offer the lowest cost – or that generate the highest net benefit where the quality of the product is non-homogeneous – naturally get used.

However, for generators – in common with other industries where transport costs are a material item – it is not possible to talk about the costs that are caused by generators given that transport costs are caused jointly by the production and consumption of electricity. In this situation, the signal for the efficient generation and consumption of a good or service can be achieved under a range of methods for dividing transport costs between generators and consumers. Indeed, decisions already have been made about how the transport costs should be attributed between producers and consumers, including that:

- **use of the shared network** – should be paid for by customers; and
- **losses** – generators should bear the cost of losses caused in transporting energy from the generator to the regional reference node and customers should bear the cost of losses caused in taking energy from the regional reference node to their premises.
Given the decisions already made about the allocation of transport costs between generators and customers, efficiency in generation is encouraged by ensuring that each generator faces the costs and benefits that it causes or creates relative to that of other generators. That is, by ensuring that each generator is exposed to the costs and benefits it causes or creates relative to other generators, the lower cost (or higher net benefit) generators naturally will be used, irrespective of the (somewhat arbitrary) apportionment of transportation charges between generators and customers.

In addition, when considering the form of price signal that is required to encourage efficient generation and consumption decisions, long term and short term dimensions to efficiency can be distinguished. In particular:

- **Long term** – for generators include whether and where to build a new plant, and for customers include whether and where to build a new plant, as well as the choice of appliances. Decisions about such matters require proponents to take a forward view of relevant market outcomes over a number of periods. It follows that efficient long term decisions may still be encouraged if the price signal reflects the average of the relative costs and benefits over a period.

- **Short term** – for generators include which generators are dispatched at a point in time, and for customers include whether to consume at a point in time. For efficient short term decisions, the price signal needs to reflect relative costs and benefits at a point in time (assuming that those relative costs and benefits are time variant).

Ensuring an equal treatment of different market participants – after allowing for differences in the costs and benefits created or caused – is often referred to as creating competitive neutrality between those participants. However, competitive neutrality is not an objective in its own right, but rather is a condition that, in the circumstances of an industry where transport costs are material and are caused jointly by generators and customers, will encourage economically efficient outcomes.

When considering how ‘signalling’ the relative costs and benefits of generation or consumption may affect the efficiency of those decisions, short term and long term decisions can be distinguished.

A characteristic of DG is that it is typically located closer to the point of consumption than traditional forms of generation, which follows from the fact that it is connected directly to the distribution network rather than the transmission network. As a result, such generation is likely to reduce electricity losses on the transmission system and, depending on where the DG is connected, possibly also on the distribution network. DSR clearly also has the capacity to reduce transmission losses and distribution losses. The focus of this section is on losses, which constitute a potentially significant source of benefit from DG compared to transmission-connected generators and from DSR compared to consumption.
5.2. Treatment of losses in dispatch and settlement

5.2.1. What are losses?

Losses consist of electrical losses, metering errors and theft. They account for approximately 10 per cent of total energy produced in Australia.\(^{36}\) Generally speaking, there is a trade-off between network utilisation and losses (i.e., as network assets are driven harder and asset utilisation improves, losses will increase). Losses also increase with the distance that energy must be transferred. The term ‘loss factor’ refers to the proportion of energy that is lost as a result of losses. The Rules distinguish three types of losses:

\[\text{Inter regional losses}\] – the losses from transporting electricity between two regional reference nodes along regulated interconnectors. NEMMCO is required to approve an equation for estimating losses, where that equation is expressed in terms of significant variables. It would appear to follow that the loss factor is recalculated for each trading interval depending upon how those variables change. The loss factor must represent the marginal losses suffered. The surplus accruing from the fact that marginal losses generally exceed average losses is treated as an interregional settlement residue and is dealt with in the same way as other interregional settlement residues.

\[\text{Intra regional losses}\] – the losses from transporting electricity between the regional reference node and any transmission connection point (transmission connection points include points of generator connection and connections to distribution networks). NEMMCO approves (static) loss factors for each transmission connection point for the year in advance (albeit with an ability to respond to new generators and other significant changes). The loss factors must represent the average of the marginal electricity losses expected in each trading interval over the year. The surplus accruing from the fact that marginal losses generally exceed average losses is treated as a settlement residue and is distributed to the TNSP (to be offset against the revenue permitted to be earned from transmission prices).

\[\text{Distribution losses}\] – the losses incurred in conveyance of electricity over a distribution network. The jurisdictional regulator must approve (static) distribution loss factors for each distribution connection point annually, in advance of the relevant year (albeit with an ability to respond to new generators and other significant changes). The loss factors must reflect the average electricity lost when conveying electricity between a transmission connection point and a distribution connection point. The ‘losses’ derived by multiplying the loss factors by throughput are required to equate to forecast total losses – so no surplus should be expected. The loss factors may be:

- site specific where size thresholds are passed (i.e., for embedded generation the threshold is 10 MW while for load it is 10MW or 40GWh) or where an embedded generator wishes to have a site specific distribution loss factor and is prepared to pay for its calculation; or

- averaged across the distribution network connection points in the relevant voltage class that are assigned to a particular transmission connection point.

5.2.2. How are loss factors used?

Loss factors are central to the NEM dispatch and settlement processes. Figure 5.1 below gives an illustrative example with explanations in the following text.

5.2.2.1. Dispatch

Central dispatch is based on (amongst other things) generator bids (clause 3.8.1). The bids that a scheduled generator submits are its bid to supply energy at that generator’s connection point (GCP). The generator’s bid is then adjusted for intra regional losses to derive the ‘offer’ that is used in central dispatch process (the objective being to work out the price that the generator is offering for energy delivered to the regional reference node, shown as ‘Bid at RRN’ in each of the outer boxes representing a generator in Figure 5.1). This is achieved by dividing the bid by the applicable intra regional loss factor (clause 3.8.6(g)) (TLF, or transmission loss factor, in Figure 5.1). If a generator is connected to the distribution network then a further adjustment is required whereby the bid is also divided by the DLF (distribution loss factor).

5.2.2.2. Settlement

The amount that a generator gets paid (or a retailer pays) – receipts in Figure 5.1 – is the product of (clause 3.15.6):

- the regional reference price;
β the intra regional loss factor at the transmission connection point (TLF in Figure 5.1).
This can be a generator connection point or a distribution connection point. All DG within the distribution network are assigned the intra regional loss factor at their allocated distribution connection point; and

β the ‘adjusted gross energy’ (‘paid for (MWh)’ in the boxes representing generators in Figure 5.1). This adjusts the energy sent out (‘dispatched (MWh)’ in Figure 5.1) to match that which is deemed to have been delivered to the transmission connection point by the DG or consumed by the retailer.

Hence, the price received (the product of the first two terms) is the ‘local spot price’ for the relevant transmission connection point (‘Spot price at GCP’ in Figure 5.1). ‘Adjusted gross energy’ for an embedded generator is measured energy multiplied by the distribution loss factor (measured energy is positive for generators, and negative for end users). ‘Adjusted gross energy’ for transmission-connected generators is just the energy that they supply (i.e. unadjusted).

5.2.2.3. The outcome of losses in dispatch and settlement

When determining which generators are dispatched, the NEM takes into account the losses incurred (or avoided) by embedded generators.

β The bids of all generators are adjusted to take account of the losses incurred (or avoided) when conveying electricity to the regional reference node, which includes losses incurred (or avoided) on the distribution network.

β If the embedded generator is in an energy importing region, then its intra regional and distribution loss factors will be greater than one, and so its bids will be scaled down when being compared to other generators. Conversely when generators are in generation rich areas they will have an intra regional loss factor that is less than 1, and so their bids will be scaled up. These effects are illustrated in the rankings of bids at the regional reference node in Figure 5.1.

The price that an embedded generator gets paid reflects the losses incurred (or avoided) when transporting electricity from the regional reference node to its transmission connection point.

β The price that all generators are paid is their local spot price, which is the regional reference price multiplied by the intra regional loss factor.

β If the embedded generator is in an energy importing region, then its intra regional loss factor will be greater than one and hence it will receive a higher price than the regional reference price.

The output that an embedded generator gets paid for reflects the losses incurred (or avoided) on the distribution network.

β The amount that the embedded generator is paid for is its output multiplied by its distribution loss factor.

β If the embedded generator is in an energy importing area, then its distribution loss factor will be greater than one, which means that it is deemed to be avoiding losses and it will get paid for more than it produces.
The amount that a retailer (on behalf of its customers) pays for electricity is the parallel of the outcome for embedded generators. In particular:

- The spot-price paid by the retailer is the regional reference price multiplied by the intra-regional loss factor for the transmission connection point (i.e. the local spot price).
- The quantity of energy for which the retailer pays is the quantity consumed by its customers, multiplied by the distribution loss factor.

And, for completeness, DSR by one of the retailer’s customers reduces the retailer’s payments to the wholesale pool by an amount equal to:

- the amount of DSR undertaken; multiplied by
- the distribution loss factor; multiplied by
- the regional reference price; multiplied by
- the intra regional loss factor.

Hence, the benefit that the retailer receives as a result of its customer’s DSR activity will include an amount in respect of the losses that are thereby avoided on the transmission and distribution networks.

In summary, the way that losses on both transmission and distribution are incorporated in dispatch and settlement is appropriate. The creation or avoidance of losses on both levels of the network (transmission and distribution) is taken into account when determining the merit order of generators and settlement (i.e. losses affect what they get paid), which will advantage generators in load-rich areas. Similarly, the amount that retailers pay for spot market purchases is affected by losses deemed to occur in transporting energy from the regional reference node to a customer’s premises. As DSR is merely negative consumption, the benefit that flows to a retailer from a customer’s DSR will incorporate an allowance for the losses that would otherwise have been incurred on the transmission and distribution networks, which in turn would be available for the retailer to pass on to the relevant customer.

However, whether the overall treatment of losses is appropriate then depends upon whether the loss factors that are used in dispatch and settlement are calculated in the appropriate manner, which is discussed next.

5.3. Analysis

As discussed above, the input that is required for dispatch and settlement is a loss factor for transmission and distribution, which reflects the proportion of energy that is deemed to have been lost when transporting energy to or from the regional reference node.\(^{37}\) When considering how loss factors should be calculated, there are at least three decisions that need to be made that will affect the accuracy of the price signal to which generators and customers are exposed (and hence, to the efficiency of decisions) which are:

\(^{37}\) More precisely, the loss factor represents the proportion of energy generated that makes it to the regional reference node, and the proportion of energy consumed that would need to have been sent out from the regional node.
Network losses

- **average vs. marginal loss factors** – that is, whether the loss factor should reflect the energy that is lost as a proportion of total energy produced at any time (i.e., the average rate of losses) or the loss that is incurred in supplying the last (marginal) unit of output;

- **time of use** – that is, whether the loss factor should be allowed to vary with the time at which generation or consumption occurs (and also whether this variation should be a preset variation, or the outcome of a dynamic calculation); and

- **location** – that is, whether (or rather, to what extent) the loss factor should vary with the location of the generator or customer.

The question of whether improvements could be made to the calculation of distribution loss factors to improve the accuracy of the price signal is addressed in turn below.

### 5.3.1. Average vs. marginal loss factors

Marginal losses (i.e., the loss caused by transporting the last unit of energy) generally exceed average losses (i.e., the loss divided by total energy transported) because the relationship between losses and energy transported is not linear – rather, losses on power lines increase with the square of the current. The loss factors for the transmission system are marginal loss factors. Hence, these factors attribute to each transmission connection point (generators or distribution network connection points) the loss that is caused by the generation or load at that connection point, compared to the loss that would have been incurred without that generator or load. This provides the correct signal when averaged over the year, given that intra regional loss factors are static for the year in advance. As noted above, fixing loss factors for a period such as a year can be consistent with encouraging efficient long term decisions, although not necessarily efficient short term decisions (the relative merits of a time of use loss factor is discussed separately below).

In principle, the efficient signal to both customers and DG would require the adjustment made for losses to reflect the change in losses that is caused by their use – i.e., a marginal loss factor. That said, calculating marginal loss factors for a large number of customers is computationally very difficult (and hence more expensive). Further, creating a marginal loss factor for end use customers within the distribution network would create a number of problems including how to allocate the surplus that would be created by the fact that payments, (reflecting marginal loss factors) would deliver revenue in excess of the total value of losses caused (reflecting the lower average loss factors).

Reflecting the costs involved in calculating marginal loss factors for distribution networks (combined with a strict reading of the requirements of the National Electricity Rules) most distribution companies calculate distribution loss factors for DG on the basis of a share of the average losses caused. However, there are some exceptions. Specifically, in Queensland both Ergon and Energex use a methodology which approximates the marginal loss factor calculation used for TNSPs for a site-specific DLF including both customers and DG. In New South Wales, Integral Energy calculates loss factors for DGs based on the difference in losses when the generator operates and when it does not operate, which is also a marginal loss factor approach.

While average loss factors may be more computationally simple to derive, using loss factors calculated in this way in dispatch and settlement understates the amount by which DG
reduces the losses on the distribution network, and thereby understates the value of DG compared to transmission connected generation. To reiterate, competitive neutrality – as a means to achieving economically efficient outcomes – requires the dispatch and settlement of generators to be adjusted for the differences in losses caused or avoided, irrespective of whether that transport is over the transmission or distribution network.

In addition, we note that one of the problems with the use of average loss factors for DG is that it creates a discontinuity in the loss factor calculated for a DG plant if the output of the DG plant is large enough to reverse the flow of electricity along the distribution assets between it and the transmission connection point. In particular, while the DG’s output is low enough for energy to be imported into the region, an average loss factor will treat it as avoiding losses (for which it will be rewarded); however, if the flow of energy reverses, then an average loss factor will treat it as causing the losses (for which it will be penalised), even though it may be reducing substantially the losses that would have been incurred in its absence. The use of a marginal loss factor for DG would avoid this anomalous outcome by requiring a comparison of the losses that would have occurred with the DG in place compared to the losses that would have occurred in its absence. Thus, even if the flow reverses, the DG will be credited with the losses it had avoided.

However, we do not consider that the argument compelling for also calculating distribution loss factors for customers on the basis of marginal loss factors. Calculating accurate marginal loss factors on a distribution network would be expected to be computationally difficult and hence costly. Moreover, we note that a consequence of our recommendation below that there should be a single (fixed) loss factor for each year ahead is that the use of marginal loss factors would only improve long term consumption decisions, but not provide materially superior price signals for DSR (i.e. being fixed, the loss factor would not signal the times when reducing consumption would have the most effect on reducing losses). Lastly, if marginal loss factors where to be used for customers as well as DG, then a settlement residue (i.e. an over recovery) would occur, which (presumably) would need to be offset against distribution prices. While Rule-changes to accommodate a distribution residue would most likely be straightforward, the (anticipated) use of price cap controls in distribution would imply that returning the residue to customers (i.e. through a reduction in distribution prices) in a manner that is revenue neutral to the distributors would require a complex mechanism (and one more complex than required where a revenue cap control is used).

**Recommendation 31.**

**DG should receive a DLF that reflects the amount of losses that the DG would avoid by being present and operating (i.e. a marginal loss factor). In contrast, customers would continue to receive a loss factor that distributes the losses to be recovered across customers in proportion to each customer’s usage, where the losses to be recovered are the sum of the forecast of actual losses and the sum of the ‘avoided losses’ from DGs.**

Where site specific distribution loss factors are calculated, this would imply forecasting the losses that would be incurred with the DG on the network and operating as forecast, to the losses that would be incurred in the absence of the DG. For the small sites – for which computational tractability would continue to require the use of an ‘averaged’ DLF, it is still proposed that a loss factor that reflects a marginal loss factor (averaged across the relevant part of the network) would be employed. However, it is noted that a practicable means of
estimating such an average ‘marginal’ loss factor would need to be established. It may be possible to establish a ‘rule of thumb’ relationship between average losses and marginal losses.

**Recommendation 32.**

**Marginal loss factors for site specific DG should be calculated on the basis of the forecast losses with the DG being present and operating as forecast, compared to the losses that would be forecast in the absence of that DG. For smaller sites, the distribution loss factor should reflect a marginal loss factor (averaged across the relevant geographic area), but estimated in a manner that keeps the computation burden to a reasonable level – for example, through the use of a ‘rule of thumb’ relationship between average and marginal loss factors.**

The immediate effects of adopting a marginal DLF for DG while retaining the average DLF for customers would be:

- in general, the loss factor attributed to an existing DG would rise in those jurisdictions that currently calculate the loss factors on an average basis (and hence increase the compensation to DG for the losses that they avoid); and
- the loss factor to customers would also rise by the amount required to fund this additional compensation to the DG:
  - however, importantly, the losses that customers would pay in respect of losses *after the DGs receive the additional compensation* would not exceed what customers would have paid in the absence of the DG.

Indeed, in following this methodology, where more than one DG connects to the same part of a distribution network, customers would receive a benefit from the connection of those DG. This reflects the fact that the losses attributable to each DG would be calculated on the assumption that that DG was the last to connect to the network. However, the actual reduction in losses will reflect the fact that the first DG reduces the losses by the greatest amount with each additional DG having less effect than the last (so the last or marginal DG will have the least effect on losses).

The following example demonstrates the proposed calculation of loss factors for DG and customers under the current approach (with the exception of Ergon and Integral) to that proposed in this report.
### Table 2.1: Calculation of loss factors

<table>
<thead>
<tr>
<th>Issue</th>
<th>No DG</th>
<th>With DG under average loss factors (existing)</th>
<th>With DG under marginal loss factors (proposed)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load</td>
<td>110 MW</td>
<td>110 MW</td>
<td>110 MW</td>
</tr>
<tr>
<td>DG</td>
<td>NA</td>
<td>10 MW</td>
<td>10 MW</td>
</tr>
<tr>
<td>Losses</td>
<td>10.8</td>
<td>9 MW</td>
<td>9 MW</td>
</tr>
<tr>
<td>DG DLF</td>
<td>NA</td>
<td>=1+9/(110-100)</td>
<td>=1+(9.8-9)/10</td>
</tr>
<tr>
<td></td>
<td></td>
<td>=1.09</td>
<td>=1.18</td>
</tr>
<tr>
<td>Customer DLF</td>
<td>=1+10.8/110</td>
<td>=1+9/(110-100)</td>
<td>1+(9.18)/110</td>
</tr>
<tr>
<td></td>
<td>=1.098</td>
<td>=1.09</td>
<td>=1.098</td>
</tr>
<tr>
<td>DG paid for</td>
<td>0</td>
<td>=1.09*10</td>
<td>=1.18*10</td>
</tr>
<tr>
<td></td>
<td></td>
<td>=10.9 MW</td>
<td>=11.8 MW</td>
</tr>
<tr>
<td>Customers pay for</td>
<td>=110*1.098 MW</td>
<td>=110*1.09 MW</td>
<td>=110*1.098</td>
</tr>
<tr>
<td></td>
<td>=120.8 MW</td>
<td>=119.9 MW</td>
<td>=120.8 MW</td>
</tr>
<tr>
<td>Net payment at transmission connection point</td>
<td>=(120.8 – 0) MW</td>
<td>=(119.9 – 10.9) MW</td>
<td>=(120.8 - 11.8) MW</td>
</tr>
<tr>
<td></td>
<td>=120.8 MW</td>
<td>=109 MW</td>
<td>=109 MW</td>
</tr>
<tr>
<td>Load at Transmission Connection point</td>
<td>=(110 + 10.8) MW</td>
<td>=(110 – 10 + 9) MW</td>
<td>=(110 – 10 +9) MW</td>
</tr>
<tr>
<td></td>
<td>=120.8 MW</td>
<td>=109 MW</td>
<td>=109 MW</td>
</tr>
</tbody>
</table>

### 5.3.2. Time of use loss factor

A further refinement to the pricing signal with respect to losses that could be created, at least in principle, is to allow the distribution loss factor to vary with time. The fact that the rate of losses depends on network loadings suggests that the loss factor would be higher at times of system peak, and lower than average otherwise. To the extent that the loss factors were expected to differ materially across time, then efficiency in short term decisions would require the loss factor to vary across time. By way of example:

- a different loss factor could be set for different trading intervals during any day (i.e. 48 loss factors for each connection point, representing the average loss factor for that trading interval expected over the year), or for peak and off peak periods during any day;
- a different loss factor for different days of the week;
- a different loss factor for different months or seasons;
- combinations of the above (e.g. a different loss factor for each trading interval for each month, implying 576 loss factors per distribution connection point); or
- a dynamic loss factor, so that the loss factor varies according to system conditions (implying that an equation explaining distribution loss factors would need to be derived for each connection point).
The short term decisions that it would be intended to influence by permitting the loss factor to vary over time would be DSR (i.e. signalling when reducing use has the most impact on reducing system losses) and generator dispatch (i.e. ensuring that dispatch decisions take account of the fact that DG would be expected to have a larger impact on losses during times of system peak).

Currently, however, the only loss factors that vary within a year are inter regional transmission loss factors, which are dynamic (i.e. are computed through an equation). Only a single intra regional transmission loss factor is approved for each transmission connection point for each year (so that the loss factor represents the average of the marginal loss factor expected in each trading interval during a day, then further averaged over the days of the year). Similarly, only a single distribution loss factor is set (although, as discussed above, currently this is generally the average of the average loss factor expected in each trading interval during a day, then averaged over the days of the year).

Expanding the number of distribution loss factors in order to better signal the change in losses expected during a year (or over a day) would increase the cost of estimating these factors and also add further complication to the settlement process. We note that the question of whether there should be time-varying loss factors was considered by NECA during its review of the scope for integrating the energy market and network services (the RIEMNS review), which concluded as follows:

Modelling by distribution network service providers shows that loss factors do not vary significantly by time of day and therefore the benefits of introducing time-varying loss factors are also unlikely to outweigh the costs. This conclusion is further supported by modelling on the time of day variability of transmission loss factors conducted by NEMMCO and Powerlink. The use of dynamic marginal distribution loss factors would provide a theoretical efficiency gain. It would come, however, with high implementation and ongoing administration and reconciliation costs.

As well as the difficulty and cost involved with calculating time-varying distribution loss factors, their introduction would create revenue risk for retailers if they varied in an unpredictable fashion. (With a static distribution loss factor, retailers are able to calculate tariffs for their end-use customers which reflect these, therefore avoiding any risk of a different loss factor applying in the calculation of their wholesale electricity prices.) Given the uncertain benefits – if actual distribution loss factors do not vary significantly during the day then the short term efficiency signal will be weak – and the probable high implementation and ongoing costs, we have not recommended a time-varying distribution loss factor.

5.3.3. Site specific vs. ‘geographically averaged’ loss factors

As discussed above, depending on the size and/or location of the DG within the network it may not be practicable to calculate the marginal loss factor of a DG. The Rules currently deal with this by setting a threshold for site specific DLFs, with the ability for a DG to ask for a

38 An increase in the number of distribution loss factors may have implications for NEMMCO’s systems, and hence impose cost.
39 NECA, 2001, Review of the scope for integrating the energy market and network services (RIEMNS review), Stage 1 Final Report, August, p.15.
site specific DLF if they pay for it. For administrative cost reasons, a cut-off must be retained, and we have no reason for believing that the current level is inappropriate. However, the fee that is charged for additional site specific DLFs could unduly penalise small embedded generators from requesting a site specific DLF. Given that the DNSP is the only party who can calculate this loss factor, any charges levied should be subject to regulatory scrutiny, and reflect an appropriate costing methodology. Under the draft Distribution Revenue and Pricing Rule, the AER would appear to have the power to list this service as one that is to be subject to regulation (for example, by requiring it to be listed as an alternative control service) and to approve a price for it. On the assumption that the relevant parts of the draft Distribution Revenue and Pricing Rule are implemented in substantially their current form, we recommend that the AER be encouraged to require the calculation of a site specific distribution loss factor to be listed as a required to be an alternative control service by listing the service in the Rules (or as a note) as an example of such a service, but – like other alternative control services – to leave the ultimate judgement to the AER. Lastly, we note that the price that is charged for the service should relate to the cost of providing the service, and that the majority of the cost presumably would be incurred to set up the relevant models to calculate the loss factor for the first year, with an immaterial cost incurred thereafter.

Recommendation 33.

The AER should be encouraged to require the price that a DNSP charges to determine a site specific DLF for a DG or a customer that is below the threshold in the Rules to be a regulated service (by listing the service in the Rules as an example of an alternative control service).

Inevitably, there will be DGs for which it is not feasible to calculate a site specific DLF, and so where a loss factor that is representative of a geographic area will need to be calculated and used. To be clear, what is being recommended for these small sites is that:

- the objective be to signal the marginal loss factor;
- the marginal loss factor referred to above is the average of this factor for the year (i.e. averaged over trading intervals and all days of the year), so that only one loss factor for a connection point is set;
- for small sites, the loss factor will represent the average of the marginal loss factor at points across a geographic area; with
- a different loss factor being set for a particular geographic area for customers that take off of different voltage levels.

However, both average (and marginal loss factors vary across distribution networks – for example, losses are generally higher at the end of long lines and hence are generally higher in the regional/remote areas. Accordingly, the extent of the geographic area over which the geographically averaged ‘marginal’ loss is calculated is important – in particular, the more that ‘high loss’ areas are combined with ‘low loss’ areas, then the greater the likelihood that the signal for small scale DG in the high cost areas will be understated (the loss factors for site specific DG are calculated for each specific site, and hence are never ‘averaged’).

Therefore, it is important to calculate, to the extent practicable, separate average loss factors for areas that are expected to experience materially different levels of losses, and to combine
areas only where they are expected to suffer materially similar levels of losses. We note that, consistent with this view, the Victorian distributors calculate a separate DLF for short and longer feeders (see NEMMCO DLFs for 2006/07). Also, Ergon has an east and west zone.

Recommendation 34.

DNSPs should be required to calculate a separate marginal loss factor for geographic regions that are expected to suffer materially different levels of losses, and to combine geographic regions for this purpose only where they are expected to suffer materially similar levels of losses.

5.3.4. Treatment of combined DG/customers

One problem that is created by the proposal is how to deal with someone who is both a DG and a customer. We propose treating the site for DLF purposes as a ‘customer’ when it imports, and a ‘generator’ when it exports on the gross flows; i.e. the generator’s DLF should apply to the site’s gross generation and the customer DLF to the gross consumption. This would treat generation and consumption decisions as independent, and reward/penalise each consistent with other generators/consumers. In order to be feasible, this would require two metered connection points at each such site: if there were only one meter, measuring net flows, the customer would have a strong incentive to overstate its internal generation as it would get paid more for what is produced than what is consumed. If the second meter was installed at the same time as the generating plant, this should help to achieve a low marginal cost for the second connection point.

The alternative we considered was to treat the site for DLF purposes as a ‘customer’ when it imports, and a ‘generator’ when it exports but on the net flows. This would be a second best solution, but the preferred one if there was only one metered connection at the site, therefore only permitting the measurement of net flows. (The use of gross flows in this case would create the incentive identified above to overstate internal generation and hence create administration and compliance problems). In this case, as an embedded generator increased output and reduced imports, it would be rewarded at the customer DLF until it reversed the flow, and then would be treated as a generator for the net flow out. A drawback of this option would be undervaluation of the internally used generation. To be feasible, it would require the ability to separately measure flows in from flows out.

Recommendation 35.

A site should be treated for DLF purposes as a ‘customer’ when it imports, and a ‘generator’ when it exports, on the gross flows of electricity, requiring two metered connection points at a site that is a combined distributed generator and customer.

5.3.5. Optimisation of losses

We have been asked to comment on whether an incentive scheme should be introduced for distributors to reduce losses. Losses are optimised where the cost of undertaking any further loss reduction activity would exceed the value of the consequent reduction in losses. This can be clearly seen with the example of network augmentation, which could reduce losses – but at the expense of building redundant network capacity. However, the concerns expressed are that a sub-optimal degree of loss reduction occurs.
The question arises because of an apparent misalignment between the incentives for those with the power to decrease losses with the interests of those who bear the costs. It is therefore important to identify the parties with the means to decrease losses, and the incentives they face. They are:

- **DG and retailers**, by substituting DG for transmission-connected generation. The primary incentives in this regard operate through the effects of loss factors on dispatch and settlement, and are addressed by the preceding recommendations in this chapter.

- **Distributors and DG**, by substituting DG for network augmentation. Distributors’ incentives in this matter operate primarily through the economic regulation of distribution. Perceived imperfections or weaknesses in these incentives are addressed by the network planning and development recommendations in Chapter 2 of this report, particularly where the reduction of losses is counted in the economic evaluation of a non-network solution to an emerging network constraint. These incentives would not, however, operate in cases where the distributor had the power to reduce losses but there was no emerging constraint to trigger the cost-benefit evaluation of non-network options.

- **Distributors**, through network augmentation. There is an apparent misalignment of incentives here: while many distributor decisions can affect losses, and the distributor is responsible for the accuracy of loss forecasts, the DNSP is not exposed to the losses (customers bear these), and retailers bear risk of forecast error. An incentive scheme could remedy these shortcomings.

Possible incentive regimes for DNSPs to optimise losses through network augmentation are:

- **Recognising the economic value of investments in the regulated asset base by reference to the wholesale market price of avoided energy losses.** IPART currently does this in NSW. Neutrality with other incentives would require an adjustment for the difference between the cost and value of the measure after a period.

- **Set DLF targets for DNSPs, and reward or penalise DNSPs for over or under performing relative to these.** Incentive arrangements like this have been implemented in UK and Ireland. It is similar to the approach to unaccounted for gas in Victorian gas distribution see Box 5.1.

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41 OFGEM, June 2003, Electricity Distribution Losses, Initial Proposals and CER, February 2004, Treatment of Losses and Global Aggregation in the MAE.
Box 5.1: Victorian treatment of unaccounted for gas

The Victorian Gas Distribution System Code (GDSC) sets out unaccounted for gas (UAFG) benchmarks for each Victorian gas distributor. The benchmarks express UAFG as a percentage of total gas deliveries, with separate benchmarks applying in respect of volumes delivered from the high and low pressure systems. The GDSC also requires distributors to use ‘reasonable endeavours’ to ensure that the quantity of UAFG in their systems is less than the prescribed benchmark. The regulatory approach applied by the Victorian Essential Services Commission (ESC) requires retailers to purchase sufficient gas from producers to cover UAFG. Victorian gas distributors are not funded for UAFG in their revenue requirements (unlike the approach in other jurisdictions). As a result retailers initially bear the cost of all UAFG. However, if actual UAFG is greater than the benchmark, the distributor is required to pay an amount to the relevant retailer(s) equal to the cost of the additional gas lost. Where UAFG is lower than the benchmark the relevant retailer(s) pay the distributor an amount equal to the cost of the gas that would have been required to meet the benchmark. The reconciliation between retailers and distributors is performed annually by the Victorian Energy Networks Corporation (VENCorp).

It is noteworthy that the Victorian ESC did not implement a DLF incentive in the 2006 price review for electricity distribution; it considered the level of losses and accuracy of forecasts to be appropriate.

Recommendation 36.

Allow, but not require, the AER to develop an incentive mechanism for DLF management guided by the principles of:

- the need to ensure DNSPs’ motivations for controlling and forecasting losses are aligned with the potential costs / benefits of changed losses or better forecasts; and
- the need for neutrality in deciding between network and non-network options
- Control of losses – rather than accuracy of forecasts – is likely to be of more significance to efficiency

Proposed clause 6.6.2 in the draft Distribution Rule appears sufficiently generic to accommodate a loss incentive scheme.

5.3.6. Relationship of averaging to other aspects of the NER

In addition to the calculation of distribution losses, averaging is employed in various aspects of network regulation to balance the efficiency of individually specified (often locational) signals and incentives with the complexity, costliness and potential obfuscation of signals and incentives arising from the large scale provision of disaggregated information.

For example, while marginal calculation of DLFs for DGs can be expected to provide enhanced signalling to the market of the loss reduction value of DG projects, it is neither practicable nor desirable for an individually calculated marginal DLF to be calculated for each network connection in the NEM. Consequently, averaging is employed as a means of
providing indicative signalling to the market where the complexity of non-averaged signalling does not warrant the benefits it would achieve.

In similar way, averaging is often employed in the specification of service incentive regimes, targets and measures, as well as in the application of network tariffs.

All Australian jurisdictions employ some degree of geographic tariff averaging or other forms of customer tariff averaging, based on customer characteristics determined by the DNSP. This is because a degree of tariff averaging will always be efficient, depending on the relative costs and benefits of providing separate prices to each individual customer connected to a DNSP’s network. In determining the efficient level of tariff averaging, a DNSP must be must take into account that it will not be efficient to continue to average all customers or locations together where:

- there is a significantly large customer or group of customers or sub-location paying prices that are above stand alone or below avoidable cost; and

- the administrative and transactions costs of levying a distinct tariff for this customer group or location are sufficiently low as to provide a net benefit to doing so. See NERA Pricing Framework Report, sections 4.2.1 and 4.4 (NERA, March 2007, pp. 23-25, 29-30)

In the case of service incentive regimes, averaging provides a means of providing an incremental reward (penalty) for improvements (deteriorations) in the overall network level of performance rather than at a given location within the network. Such averaging is consistent with the use of geographically averaged tariffs such that the average customer incurs the costs of an average improvement in service, rather than the case where the average customer incurs the additional cost of enhancing service levels to a specific location. Use of averaging versus locational based service incentive targeting is discussed further in NERA DSR and DG Review Report Part One, section 6.1.2 (NERA, March 2007, pp. 34-35).

These illustrative examples of the efficient use of averaging highlight that it is necessary for the Rules to avoid preventing the use of averaging as an effective means of balancing the benefits of individually targeted signalling and/or incentives with the costs of providing these.
Appendix A. Victoria

A.1. Network planning

<table>
<thead>
<tr>
<th>Instrument</th>
<th>Title</th>
<th>Relevant provision</th>
</tr>
</thead>
<tbody>
<tr>
<td>Licence</td>
<td>Electricity Distribution</td>
<td>Must comply with Electricity Distribution Code (22.1(b)(1))</td>
</tr>
<tr>
<td>Code</td>
<td>Code 2006</td>
<td>Requires DNSP to publish annual planning report (3.4 and 3.5)</td>
</tr>
</tbody>
</table>

The key legal instruments and regulatory arrangements pertaining to network planning are contained in the Electricity Distribution Code 2006. As compliance with this code is a licence condition, failure to meet the planning requirement could potentially be treated as a breach of licence

A.1.1. Periodic planning and reporting requirements

Under the Electricity Distribution Code a distributor must submit two annual reports, a Transmission Connection Planning Report and a Distribution System Planning Report.

The Transmission Connection Planning Report details how a distributor plans to meet predicted demand for electricity supplied into their distribution network form transmission connections over 10 years. The report includes:

- historical and forecast demand and the capacity of each transmission connection;
- an assessment of the magnitude, probability and impact of a loss of load at each transmission connection;
- each distributor’s planning standard;
- a description of feasible options for meeting forecast demand at each transmission connection point, including embedded generation and demand management;
- the availability of any contribution from each distributor, which is available to embedded generators or customers to reduce demand and avoid/defer augmentation; and
- a description of any preferred options, including estimated cost.

The Distribution System Planning Report (DSPR) details how the DNSP plans to meet predicted demand and to improve reliability for customers over the next five years.

The report includes a number of features designed to increase the transparency of how network augmentations are planned, in doing so it must include:

- historical and forecast demand as well as the level of capacity at each zone sub station;
- an assessment of the magnitude, probability and impact of a loss of load for each sub transmission line and zone substation;
a description of feasible options for meeting forecast demand at each connection point, including embedded generation and demand management;

- the availability of any contribution from each distributor available to embedded generators or customers to reduce demand and avoid/defer augmentation; and

- a description of any preferred options, including estimated costs

A.1.2. Consideration of non-network alternatives

One of the main aims of the Distribution System Planning Report is to allow proponents of non-network alternatives the opportunity to consider providing network support services. The DSPR requires the DNSP to describe feasible options for either embedded generation or demand management.

A.1.3. Case-by-case project assessment and consultation

Aside from the requirement that the DSPR identify where potential non-network solutions could arise, there are no requirements for a formal notification process or request for proposals where a specific augmentation is proposed to relieve a network constraint.

A.1.4. Evaluation of options - economic test

It does not appear that Victorian distributors are required to publish any formal appraisal of augmentation options along the lines of the Regulatory Test contained in the NER.

A.1.5. Regulatory oversight or dispute resolution

There are no formal dispute resolution procedures for the network planning requirements under the code.

A.2. Network connections and connection charges

The current regulatory arrangements in Victoria pertaining to connection applications and the payment of connection charges are governed by a combination of the NER and state-based legislation.

Rule 9.7.4 of the NER states that for the purposes of regulating distribution services in Victoria the Essential Services Commission (ESC) will be responsible for regulating all aspects including issues arising in the connection process set out in Rule 5.3. In accordance with Rule 9.7.4(d) the ESC will be responsible for considering any questions about the fairness and reasonableness of an offer to connect arising from Rule 5.3.6(c). Any disputes arising in relation to connection or a modification of connection must also be resolved in accordance with procedures set out by the ESC and Rule 8.2 will not apply.

The following table provides a summary of the state-level legislation and regulatory instruments pertaining to the regulation of connections in Victoria.

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43 This Rule contains the NER’s provisions for dispute resolution.
Table A.2: Victorian connection regulatory instruments

<table>
<thead>
<tr>
<th>Instrument</th>
<th>Title</th>
<th>Relevant provisions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Legislation</td>
<td>Electricity Industry Act 2000</td>
<td>Grants regulatory power over electricity industry to ESC (s 12)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Requirements for standard contracts (s 21e)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Requirement for customer dispute resolution scheme (s 28)</td>
</tr>
<tr>
<td>Legislation</td>
<td>Essential Services Commission Act 2001</td>
<td>Allows ESC pricing control in regulated industries (s 32, 33)</td>
</tr>
<tr>
<td>Order</td>
<td>Victorian Electricity Supply Industry Tariff Order 2005</td>
<td>Lists connection services as Excluded Services and allows capital contributions for new works and augmentation (Attachment Part A)</td>
</tr>
<tr>
<td>Code</td>
<td>Electricity Distribution Code</td>
<td>Obligation to connect (s 2.2)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Good faith negotiation with embedded generators (s 7.1.2)</td>
</tr>
<tr>
<td>Guideline</td>
<td>Electricity Industry Guideline Number 5: Connection and Use of System Agreements 1996</td>
<td>Negotiation around standard principles acceptable (s 1.5)</td>
</tr>
<tr>
<td>Guideline</td>
<td>Electricity Industry Guidelines Number 14: Provision of Services by Electricity Distributors 2004</td>
<td>Regulation of prices for excluded services including connection services (cl 5)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Capital contributions (cl 3)</td>
</tr>
<tr>
<td>Guideline</td>
<td>Electricity Industry Guidelines Number 15: Connection of Embedded Generation 2004</td>
<td>Standard agreements for small generators (s 3.2)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>ESC to make decisions where there is a negotiation dispute (s 2.4)</td>
</tr>
</tbody>
</table>

The remainder of this appendix provides an overview of the legislative and regulatory arrangements relating to network connections and connection charges operating in Victoria.

### A.2.1. Network connection arrangements

Pursuant to sections 32 and 33 of the *Essential Services Commission Act 2001* and section 12 of the *Electricity Industry Act 2000* (Electricity Industry Act), the ESC has the power to regulate energy distribution. The principle regulatory instrument is the Electricity Distribution Code (Code).

#### A.2.1.1. Obligation to connect

The various regulatory instruments do not explicitly contain an obligation to connect, however, such an obligation is implied by the Code, which contains required timeframes for connections.\(^{44}\) Section 2.2 of the Code requires a DNSP to connect within 10 business days

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\(^{44}\) Victorian Energy Distribution Licences do contain an obligation to connect in clause 6, but this is stated to be “subject to the Electricity Distribution Code”.
(or an agreed date) following a request. This request may be made by a retailer acting on behalf of a customer or can be made by the customer if the customer is a market customer in the wholesale market.

The DNSP’s obligations to connect are subject to the conditions contained in section 2.6 of the Code including an adequate supply of electricity being available at the boundary of the new supply address and various safety requirements being met.

A.2.1.1. Connection of DGs

Section 7.1.2 of the Code states that if a DG seeks connection then the DNSP and DG must negotiate in good faith. Sections 7.2 to 7.8 detail the technical requirements that DGs must meet in order to be connected to the distribution network.

A.2.1.2. Connection agreements

The ESC’s Electricity Industry Guideline Number 5: Connection and Use of System Agreements provides some guiding principles for connection agreements. The guideline also provides for negotiation around these principles as required.

A.2.1.2.1. Standard contracts

As a condition of its licence DNSP’s may be required to prepare standard agreements for the purposes of sections 21(c) and (d) of the Electricity Industry Act. These agreements must be approved by the ESC.

A.2.1.2.2. Negotiated contracts

Guideline 5 implies that customers and DNSPs are able to negotiate variations to standard form contracts at terms agreeable to both parties. There are no express provisions relating to the manner by which this negotiation will be undertaken.

A.2.1.2.3. DG contracts

The ESC’s Electricity Industry Guideline Number 15: Connection of Embedded Generation Issue 1 provides guidance on DG contracts. As well as restating the good faith negotiation requirement of the Code, section 2.2 of the Guideline states that the DNSP must provide the DG with reasonable information to enable it to make its decision.

Additionally, section 3.2 of Guideline 15 requires DNSPs to have a fair and reasonable standard connection agreement for small DGs, as approved by the ESC.

45 Additional sections in Chapter 2 of the code give timeframes for connection without energisation (20 days or an agreed date) and for energisation of a previous connection (within 1 business day if the request is made by 3pm).

46 Section 1.2 – “distributors, retailers and customers are free to negotiate innovative variations based on these principles”.
A.2.1.3. Arbitration framework

Section 28 of the Electricity Industry Act states that any license to distribute electricity will only be issued if the licensee enters into a customer dispute resolution scheme approved by the ESC. Approval of this scheme is to be guided by cost, accessibility and harmony with the goals of the relevant Acts.

In relation to DGs, section 2.4 of Guideline 15 states that if a dispute arises during negotiations then the ESC will be the relevant arbiter.

A.2.2. Connection charges and capital contributions

A.2.2.1. Regulation of connection charges

Clause 5 of the ESC’s Electricity Industry Guideline Number 14: Provision of Services by Electricity Distributors deals with the general regulation of pricing for excluded services, including connection charges. Clause 5.1.2 notes that all DNSPs must submit for the ESC’s approval a statement of their proposed charges for all excluded services, which includes connection charges. Clause 5.6 lists the principles that a DNSP should follow in its pricing in order to receive ESC approval. These principles relate to fairness and reasonableness in calculating attributed costs.

Clause 5.2 of the guideline states that any person may request that the ESC make a decision on whether any excluded service is contestable; any contestable excluded service will not be subject to the ESC’s approval.

A.2.2.1.1. DG

Connection services for DGs are currently defined by the ESC as non-contestable excluded services and thus are subject to the same regulation as that set out in the preceding section.

A.2.2.2. Capital contributions

The Victorian Electricity Supply Industry Tariff Order 2005 lists as an excluded service capital contributions for new works and augmentation.

Clause 3 of the ESC’s Guideline 14, provides guidance as to how these should be calculated. Clause 3.1.3 states that new works and augmentation may form part of the connection services a distributor provides to a customer so as to allow the supply of electricity from the distributor’s distribution system to an electrical installation of the customer. Clause 3.2 further states that a customer may only be required to make a capital contribution if the incremental cost in relation to connection is greater than incremental revenue, and that the contribution may not be greater than this difference. The customer’s capital contribution is to be calculated in accordance with clause 3.3 ie.;

\[ CC = [IC – IR] + SF \]

47 The Victorian Electricity Supply Industry Tariff Order 2005 specifies which services are classified as excluded, and includes “connection to the Distributor’s Distribution System”.
Where $CC =$ capital contribution, $IC =$ incremental cost *relating to connection offer*, $IR =$ incremental revenue *relating to connection offer*\(^{48}\) and $SF$ is the amount of any security fee.\(^{49}\) The rest of Clause 3.3 clarifies the rules for calculating each of these items.

Clause 3.4 provides special rules for group extensions and pioneer schemes. The former essentially states that if the DNSP is providing services to more than one customer, the previous rules must be used but may be adapted to ensure equity. The latter provides that if a new customer makes use of works already contributed to by a “pioneer customer” that they would have had to contribute to had that customer not done so first, the DNSP must make arrangements to ensure that contributions are equitable, which may include a rebate to the pioneer paid for by a contribution by the new.

**A.2.2.2.1. DG**

Clause 3.3.2(b)(1)(A) of Guideline 15 states that DG connection may attract a capital contribution referable to the present value of incremental costs of shallow augmentation required for the connection of the embedded unit.\(^{50}\)

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\(^{48}\)“Relating to connection offer” is italicised as it is the key phrase determining what costs and revenues are included. Costs include direct incremental costs minus savings made, an example being the recoverable costs of assets no longer used. The relevant revenues are the distribution charges over a given period – 30 years for residential customers, 15 years for business.

\(^{49}\)The details of which are contained in Clause 3.5.

\(^{50}\)Shallow augmentation is defined as the installation of network assets and any augmentation of the distribution system up to and including the first transformation in the distribution system in respect of the embedded generator. Deep augmentation – any other augmentation – is expressly not allowed to be passed through.
Appendix B. New South Wales

B.1. Network planning

Table B.1: New South Wales network planning regulatory instruments

<table>
<thead>
<tr>
<th>Instrument</th>
<th>Title</th>
<th>Relevant provision</th>
</tr>
</thead>
<tbody>
<tr>
<td>Legislation</td>
<td>Electricity Supply Act 1995</td>
<td>Requires DNSP to hold a licence. Requires government to impose licence conditions on DNSP to conduct and publish investigations on the cost effectiveness of implementing demand management strategies and to publish an annual report in relation to those investigations (Schedule 2(6)(5)).</td>
</tr>
<tr>
<td>Regulation</td>
<td>Electricity Supply (safety and management) Regulation 2002</td>
<td>Requires DNSP to produce a network management plan (5(1)(d)), including an annual Network Performance Report, which measures performance against this plan (Clause 16).</td>
</tr>
<tr>
<td>Guidance document</td>
<td>Electricity Network Performance Outline</td>
<td>Stipulates the information to be provided in the Network Performance Report, includes reporting requirements for demand management activities and investigations.</td>
</tr>
<tr>
<td>Licence</td>
<td>New South Wales Distribution Network Service Provider licence</td>
<td>Requires DNSPs to publish investigations on demand management opportunities (licence condition 3.1).</td>
</tr>
<tr>
<td>Code</td>
<td>New South Wales Demand Management Code</td>
<td>Provides guidance on how to meet requirements of licence relating to demand management and planning.</td>
</tr>
</tbody>
</table>

The New South Wales Demand Management Code provides guidance on meeting a licence condition any failure to meet the requirements of the code could potentially be regarded as a licence breech.

Penalties may also be imposed for failure to comply with Electricity Supply (safety and management) Regulations 2002 which require the DNSP to take into account the demand management code.

B.1.1. Periodic planning and reporting requirements

DNSPs in New South Wales are required to produce two planning documents:

- under the Electricity Supply (safety and management) Regulation 2002, each DNSP must also produce a Network Management Plan; and
- under the Demand Management Code of Practice each DNSP must produce an annual Electricity System Development Review (ESDR) as part of its Network Management Plan.

The EDSR is designed to facilitate the development of non-network solutions to capacity constraints. The ESDR includes:

- emerging network constraints over five years;
Appendix B

Allen Consulting Group and NERA Economic Consulting

β data and information that can be used to identify cost effective system support alternatives;
β historic and forecast peak load and capacity, including ten years of historic data and forecasts for the next five years; and
β a description of the planning guidelines.

The level of detail required in the EDSR depends on the nature and expected timing of the emerging constraint, for example:

β a low level of detail is required across the whole system to indicate where constraints might emerge in the foreseeable future;
β a medium level of detail for parts of the network where a constraint is forecast within the next five years,51 and
β an additional higher level of detail where action clearly needs to be taken to address specific forecast constraints (see request for proposals).

B.1.2. Consideration of non-network alternatives

The Electricity Supply Act 1995 requires the government to impose licence conditions on the DNSPs to conduct and publish investigations on the cost effectiveness of implementing demand management strategies that may permit distribution network augmentation work to be avoided or postponed.

The Demand Management Code of Practice provides guidance to DNSPs on how to meet this licence obligation. This code of practice was developed by a working group including the New South Wales DNSPs, TNSPs, IPART, electricity use representatives, the New South Wales Government and was chaired by Integral Energy.

In accordance with this code of practice DNSPs are required to keep a register of interested parties that wish to be informed in relation to each supply constraint forecast to occur within five years. The code of practice also requires DNSPs to issue a formal Request for Proposals (RFP), calling for non-network solutions in relation to a specific constraint, in the event that it passes a Reasonableness Test. Essentially this is any proposal where the total annualised cost is likely to be greater than $200,000.

Each step of the code of practice is supported and informed by documented protocols.

51 This includes: forecasts of for the next five years of total capacity (firm and peak load), extent of overload, length of overload, frequency of overloads and power factor at time of overload. Other information regarding reliability/security standards, load/trace data for current peak day, annual load duration and nature of the load, including customer information, such as the type of customer, specific key loads and principle growth drivers. The DNSP must also identify possible system support options for overcoming the constraint and estimated cost and provide a forecast date the system support options would be needed.
B.1.3. **Case-by-case project assessment and consultation**

Where a zone or substation is facing a constraint within the next five years, the DNSP must consult with interested parties to raise awareness of the upcoming constraint and explore possible non-network solutions before it issues an RFP. As part of this process a DNSP can invite third parties to prepare an investigation of potential demand management options, recovering any payments made through the price determination process. Before it can go ahead with a network augmentation it must call for formal submissions by issuing an RFP.

The RFP can specify an indicative, fixed or maximum price that will be paid for system support, or it may leave bid prices to be determined by proponents. The code of practice provides detailed guidance on what needs to be in the RFP, including:

- the level and timing of the system support required,
- the results of any investigations with customers;
- data regarding the types of customer and loads of the largest existing customers; and
- all relevant assumptions to be used in the evaluation of proposals.

The timing of the RFP should allow:

- at least eight months before the forecast date that the system support investment decisions must be made; and
- at least eight weeks for submissions of the proposals.

As well as specifying closely the details of what needs to be included in the RFP the code of practice also specifies precise details of what needs to be included in any proposals. Proponents may also submit draft proposals to the DNSP for comment prior to the final date for submissions.

B.1.4. **Evaluation of options - economic test**

Under the code of practice all proposals are evaluated and ranked on the basis of the total annualised cost of providing the system support. That is, the cost incurred by the DNSP plus the sum of any changes to the level of transmission or distribution losses. This cost is then adjusted to account for the relative risk profile of options.52

A ten year period for evaluation is recommended, although if a sound rationale is provided a different period may be chosen.

As well as considering each proposal on an individual basis the DNSP can combine separate proposals and consider them in combination with each other.

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52 The relative intrinsic risk profile of each option should be evaluated according to standard industry practice. The Code here notes that a perceived risk, which reflects simply the lack of familiarity of demand side response by a DNSP, can be a major barrier to system support options.
After agreeing to utilise a non-network proposal the contract the distributor enters into may be staged, with interim progress payments made to allow one of the parties to withdraw at some stage in the process if the proposal is subsequently not expected to achieve the required outcome.

B.1.5. Regulatory oversight or dispute resolution

Under the Electrical Supply (safety and Network Management) Regulations 2002, DNSPs are required to lodge a Network Management Plan with the government. Part of this is an annual performance report, which now includes details regarding demand management activities and investigations.

Although there is no formal mechanism for reviewing the evaluation process undertaken by a DNSP, failure to comply with the demand management code of practice would be a breach of the DNSPs licence. Moreover, the New South Wales Demand Management Working Group has noted that IPART will scrutinise the prudence of all investments (both network and non-network projects) as part of the decision on the roll-forward of the regulatory asset base at the time of the regulatory review. DNSPs that are found not to be developing their network in a least cost method would run the risk of having investments excluded from their asset base at the review.\(^{53}\)

There is no dispute resolution role if a party disagrees with the option selected by the DNSP.

B.2. Network connections and connection charges

The current regulatory arrangements in New South Wales pertaining to connection applications and the payment of connection charges are governed by a combination of the NER and state-based legislation.

The jurisdictional derogations contained in Rule 9.15.2 states that IPART is to act as the Adviser in any dispute regarding access arises involving two or more Registered Participants which is not resolved within 10 business days.\(^{54}\) If IPART thinks it appropriate, it may also act as the dispute resolution panel under Chapter 8 of the NER, as long as arrangements are made so that no party is adversely affected by it doing so having previously acted as the Adviser. If IPART is unable or unwilling to do so it must appoint a panel in accordance with Chapter 8.

The following table provides a summary of the state legislation and regulatory instruments pertaining to the regulation of connections in New South Wales.

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53 Note Network Planning, Network Demand Management Consultation Working Group, 28 April 2005
54 Or another period agreed to by all parties.
Table B.2: New South Wales connection regulatory instruments

<table>
<thead>
<tr>
<th>Instrument</th>
<th>Title</th>
<th>Relevant provisions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Legislation</td>
<td>Electricity Supply Act 1995</td>
<td>Obligation to connect (s 15) Customer contracts (Part 3, Divisions 2 and 3) Dispute resolution (Part 8) Allowance for capital contributions (s 25)</td>
</tr>
<tr>
<td>Legislation</td>
<td>Independent Pricing and Regulatory Tribunal Act 1992</td>
<td>Power of IPART to make determinations (Part 3, Division 5)</td>
</tr>
<tr>
<td>Regulation</td>
<td>Electricity Supply (General) Regulation 2001</td>
<td>Situations where DNSP may refuse connection (s 14) Details of ombudsman scheme (Part 6)</td>
</tr>
<tr>
<td>Relevant regulatory decisions</td>
<td>Capital Contributions and Repayments for Connections to Electricity Distribution Networks in New South Wales 2002</td>
<td>Complete document</td>
</tr>
<tr>
<td>Relevant regulatory decisions</td>
<td>Regulation of Excluded Distribution Services Rule 2004</td>
<td>Pricing of excluded services including connection services (s 2.2a1)</td>
</tr>
</tbody>
</table>

The remainder of this appendix provides an overview of the network connection arrangements prevailing in New South Wales and the role of capital contributions within this process.

B.2.1. Network connection arrangements

B.2.1.1. Obligation to connect

Section 15 of the Electricity Supply Act 1995 (Electricity Supply Act) states that a DNSP must provide connection services to any person who owns or occupies premises within the DNSP’s distribution area, unless that person is entitled to provision of connection services within a wholesale market access regime. This obligation is, however, subject to any other sections of the Act or regulations regarding disconnections or refusal to connect.55

B.2.1.2. Connection agreements

Section 18 of the Electricity Supply Act states that no customer can be connected to a DNSP other than through a customer connection contract.

B.2.1.2.1. Standard contracts

Section 19(1) of the Electricity Supply Act imposes (as a condition of this licensing) an obligation on the DNSP to prepare a standard form customer connection contract. Section 19(3) further states that different classes of customer may have different customer connection contracts. Section 20 sets out the matters that must be included in the contract which

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55 This section lists conditions that may invalidate the right to connection, including non-payment of fees and obstruction of a DNSP’s authorised officer.
includes the basis on which connection charges are calculated, the security to be provided by customers, the standard of service and the dispute resolution mechanism. There is no specific requirement for regulatory approval of this contract, however, to the extent that the contract is inconsistent with the Electricity Act it will be unenforceable.

The Electricity Supply (General) Regulation 2001\(^6\) contains a number of other provisions for customer contracts, however, these provisions primarily relate to administrative matters.

**B.2.1.2.2. Negotiated contracts**

Section 23 of the Electricity Supply Act provides for the use of negotiated connection contracts. In accordance with section 23(2) such a contract may contain such terms as the distribution network service provider and customer may agree, and the contract is enforceable accordingly. Other provisions within this section state that the negotiated contract must comply with any conditions imposed on the DNSP in its licence, however, it is not unenforceable merely because of any failure to do so. The negotiated contract must also not be inconsistent with the provisions of the Electricity Supply Act or regulations, and is unenforceable to the extent of any such inconsistency.

**B.2.1.3. Arbitration framework**

Part 8 of the Electricity Supply Act contains provisions relating to appeals and the resolution of disputes. In accordance with section 96 a customer may apply for an internal review of a decision, while section 96A provides for an ombudsman scheme if such a review is unsuccessful. Section 96D of the Electricity Act provides that negotiated contracts may contain provision for other forms of dispute resolution if required.

**B.2.2. Connection charges and capital contributions**

**B.2.2.1. Regulation of connection charges**

Connection services are currently defined as an excluded service and as such any connection charges must comply with the pricing principles contained in IPART’s 2004 Regulation of Excluded Distribution Services Rule.

All excluded distribution services come under these pricing principles unless they are able to satisfy the Competition Test in Annexure 2. That is the DNSP can prove that there is effective competition in the market for the service.

**B.2.2.2. Capital contributions**

Section 25 of the Electricity Supply Act states that a DNSP may require a new customer to contribute towards the costs incurred in the extension or augmentation of the network required for that customer to receive connection services. Section 25(2) also states that a customer may be required to contribute to previously incurred costs of other customers in the same vicinity. Any capital contribution must, however, comply with any determinations in force under the Independent Pricing and Regulatory Tribunal Act 1992 (section 25(3)).

\(^6\) Division 4, Part 1; Schedule 3.
relevant determination in this context is IPART’s 2002 Capital Contributions and Repayments For Connections to Electricity Distribution Networks in New South Wales (Determination).

In accordance with this Determination customers must pay for the direct costs of establishing the connection up to a defined point of connection to the network\(^{57}\) – the direct costs involved in providing and installing lines and equipment dedicated to that customer. Customers in rural areas and large load customers, however, may also have to contribute to augmentation costs. DNSPs are required to establish a scheme to reimburse these latter two types of customer for some of their contributions in the event that other customers use the assets they have paid for at a later date. IPART stipulates that the principles used to determine capital contributions should be consistent to its approach to regulating other network prices, as outlined in its Pricing Principles and Methodologies.

The Determination includes rules for multi-occupant developments\(^{58}\) and a stipulation that DNSPs should consider the prospect for network expansion in the medium term. This latter stipulation is a result of the limitation of the reimbursement scheme to rural and large load users and is designed to ensure that if it is likely that further network expansion will take place in the customer’s locality that the connection point is set accordingly.

For the purposes of requiring contributions to augmentation, a rural customer is defined as a customer in those parts of the network where the “after diversity maximum demand” per kilometre of line is less than 300kVA, based on high voltage feeders. DNSPs may also apply a test based on local council zoning. A large load customer is defined as a customer whose expected demand for electricity is such that the customer would require more than 50 per cent of the capacity of the existing network to be augmented.

The reimbursement scheme operates for seven years from the date that the original customer makes an application for connection works. The Determination also provides, in section 3.4, for dispute resolution. Disputes in relation to capital contributions up to $20,000\(^{59}\) are to be referred to the Energy and Water Ombudsman of New South Wales, while higher amounts will be referred to one of a panel of independent experts.

\(^{57}\) This point has been defined by IPART as the point on the network at which the use of assets changes from shared among customers generally to dedicated to one or more customers.\(^{\text{57}}\)

\(^{58}\) Broadly, the developer should pay for all low and high voltage assets that will be dedicated to the development.\(^{\text{58}}\)

\(^{59}\) Up to $50,000 if the DNSP agrees.\(^{\text{59}}\)
Appendix C. Queensland

C.1. Network planning

Table C.1: Queensland network planning regulatory instruments

<table>
<thead>
<tr>
<th>Instrument</th>
<th>Title</th>
<th>Relevant Provision</th>
</tr>
</thead>
<tbody>
<tr>
<td>Legislation</td>
<td>Electricity Act 1994</td>
<td>Requires a DNSP to be licensed (Section 195) and comply with approved codes (Section 55)</td>
</tr>
<tr>
<td>Legislation</td>
<td>Electricity Regulation 2006</td>
<td>Approves Electricity Industry Code as the approved code under the Act (section 87)</td>
</tr>
<tr>
<td>Code</td>
<td>Queensland Electricity Industry Code</td>
<td>Requires DNSP to produce a Network management plan (section 2.3)</td>
</tr>
</tbody>
</table>

Aside from issues relating to the regulation of price, which is overseen by the Queensland Competition Authority (QCA), most other regulatory functions, such as licensing, are assigned to the Director General, Department of Mines and Energy.

Failure to comply with the reporting requirements under the Queensland Electricity Industry Code (Code) would be a breach of the *Electricity Act 1994*, it is not clear if this is currently enforced through a license provision.

C.1.1. Periodic planning and reporting requirements

Under the Code all DNSPs are required to produce two types of planning documents:

- an annual Network Management Plan (NMP); and
- if requested by the Regulator, a summer preparedness plan.

The NMP is the key network planning document, setting out how the DNSP will manage and develop its supply network. Information that must be included in the NMP include:

- an explanation of the background to the network management plan and its purpose;
- general information about the DNSP’s supply network;
- a statement of the DNSP’s planning policy and a qualitative assessment of its compliance with that policy;
- a statement of the DNSP’s asset management policy (including its current key programmes) and a qualitative assessment of its compliance with that policy;
- an analysis of the historical reliability performance for the previous five years;
- the operating environment, including growth forecasts;
- a statement of reliability targets for the next five years and a description of major existing and planned reliability improvement programs, including details of major capital and operating and maintenance expenditure initiatives;
- an evaluation of the DNSP’s performance in the preceding financial year against the network management plan for that year, including implementation of major capital and operating and maintenance expenditure initiatives.
 producing a risk assessment of the major constraints in the distribution entities network and how
they may be alleviated;
β how worst performing feeders are defined and an analysis of the performance of worst
performing feeders in the past financial year and of worst performing feeders in the
preceding network management plan; and
β the DNSP’s demand management strategy, including a description of the existing and
planned programs and opportunities for demand side participation.

By identifying emerging constraints and the likely location of network augmentations, the
Queensland DNSPs treat the Network Management Plan as the key document signalling areas
where demand management proponents could potentially be engaged. For example, Ergon
describes part B of its 2006 NMP as detailing:

the specifics of our network capability and works planning. It also facilitates a process for public consultation and
stakeholder feedback on network constraints, supply issues and proposed solutions.

C.1.2. Consideration of non-network alternatives

The only formal requirement for considering non-network alternatives is the requirement for
the DNSP to develop a demand management strategy as part of its NMP.

C.1.3. Case-by-case project assessment and consultation

Aside from the requirement to publish an annual plan, the regulatory arrangements in
Queensland appear to place no obligation on the participants to consult on specific proposed
augmentations or request proposals for alternative non-network solutions.

C.1.4. Evaluation of options - economic test

There is no requirement under state legislation for any form of cost benefit test to be
conducted on augmentations less than $10 million. For large network assets the requirements
under the NER apply.

C.1.5. Regulatory oversight or dispute resolution

There is no formal mechanism to dispute the outcomes of the planning process undertaken by
a DNSP in Queensland.

C.2. Network connections and connection charges

The current regulatory arrangements in Queensland pertaining to connection applications and
the payment of connection charges are governed by a combination of the NER and state-
based legislation.

The jurisdictional derogations contained in Rule 9.37.4 state that responsibility for the
regulation of connection to a Queensland distribution network lies with the Queensland Competition Authority60 (QCA). If a dispute arises in relation to connection, that dispute

60 Although the Minister is able to confer this power on a national body.
must be resolved in accordance with Chapter 8\(^\text{61}\) and the QCA has the jurisdiction to rule on the fairness and reasonableness of an offer under Rule 5.3.6(c). The following table provides a summary of the state legislation and regulatory instruments pertaining to the regulation of connections in Queensland.

**Table C.2: Queensland connection regulatory instruments**

<table>
<thead>
<tr>
<th>Instrument</th>
<th>Title</th>
<th>Relevant provisions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Legislation</td>
<td>Electricity Act 1994</td>
<td>Obligation of a DNSP to connect (ss 40 and 40E)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Provision made for standard customer connection contracts (ss 40 and 40A)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Provision made for negotiated connection contracts (ss 40 and 40C)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Connection to be made on fair and reasonable terms (s40D)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Defines connection services (schedule 5)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Dispute resolution mechanism (s 119)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Role of regulator to make standards and codes and act as arbitrator (s63)</td>
</tr>
<tr>
<td>Regulations</td>
<td>Electricity Regulation 2006</td>
<td>Limits to DNSP’s obligation to connect (ss 31 and 34)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Customer’s obligation in relation to connection (s 35)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Defines what will not constitute unfair or unreasonable terms (ss 63, 64 and 66)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Dispute resolution mechanism for disputes relating to ‘fair and reasonable’ (Part 4)</td>
</tr>
<tr>
<td>Code</td>
<td>Electricity Industry Code (20 July 2006)</td>
<td>Terms for standard customer connection contract (Annexure A)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Contestable customers to pay connection charge to DNSP with charges determined from time to time in accordance with regulatory instruments (cl. 10.2 - 10.3)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Non-contestable customers to pay connection charge to retailer (cl. 10.1)</td>
</tr>
<tr>
<td>Relevant regulatory decisions</td>
<td>Regulation of Electricity Distribution - Final Determination - April 2005</td>
<td>Defines connection services as a prescribed service. Sets out treatment of capital contributions in regulatory model.</td>
</tr>
<tr>
<td>Other</td>
<td>Ergon and Energex Pricing Principle Statements</td>
<td>Contains capital contributions policy for connections for standard users, embedded generators, connection asset customers and individually calculated customers</td>
</tr>
</tbody>
</table>

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\(^{61}\) Chapter 8 deals with various administrative functions, including dispute resolution.
The remainder of this appendix provides an overview of the network connection arrangements prevailing in Queensland and the role of capital contributions within this process.

**C.2.1. Network connection arrangements**

**C.2.1.1. Obligation to connect**

In accordance with section 40 of the *Electricity Act 1994* (Electricity Act) a DNSP has an obligation to provide customer connection services to premises within the DNSP’s distribution area. A DNSP may connect a customer outside its distribution area, however, it may only do so if the connection is not likely to impair its capacity to fulfil its obligation to connect and supply in its own distribution area. The term customer connection service is defined in Schedule 5 of the Electricity Act which states that:

…customer connection services, for premises, means--(a) the connection of the premises to a supply network to allow the supply of electricity from the supply network to the premises; and (b) the supply of electricity from the supply network to the premises.

The DNSP’s obligation to provide a connection service may be limited if any of the events described in section 40E of the Electricity Act or section 31 of the Electricity Regulation (2006) arise. Section 34 of the Electricity Regulation (2006) also enables the DNSP to refuse to provide a connection service in a number of defined circumstances including the failure of the customer to pay a capital contribution or to make a reasonable advance payment for charges for providing customer connection services to any premises of the customer.

**C.2.1.1.1. Connection of DGs**

In accordance with section 43 of the Electricity Act 1994 a DNSP must also allow, as far as technically and economically practicable, a generator to connect supply or take electricity from its supply network on fair and reasonable terms if:

- the network is capable of being safely used to connect taking into account:
  - the DNSP’s current obligations and its expected future obligations;
  - the current obligations of other persons connected directly or indirectly to the network; and
  - the network’s capacity.

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62 These events include, amongst other, an emergency, circumstances beyond the DNSP’s control, the connection would breach a technical requirement of the Act, the connection or supply would unreasonably interfere with the connection or supply of electricity by the distribution entity to other customers.

63 These events include the applicant not asking for services in a way approved by the entity, the applicant applies for the supply of electricity at a rate more than the maximum capacity of the connection to the supply network, the applicant does not a reasonable advance payment for the charges for providing the services, a reasonable security, a capital contribution towards the costs incurred, or to be incurred, by the entity in extending, or increasing the capacity of its supply network to provide the services to the premises.
the generator has complied with all the provisions of the regulations relevant to connecting supply which includes:

- entering into an agreement with the DNSP which sets out the conditions for securing safe and stable parallel operation of the supply network and the generation plant (Electricity Regulation 28); and

- complying with the technical conditions of connection to the network stated in its generation authority or prescribed under regulations (Electricity Act section 27).

the generator pays the reasonable cost of connection to the network.

C.2.1.2. Connection agreements

C.2.1.2.1. Standard contracts

Section 40 of the Electricity Act also provides for the use of either a standard or negotiated customer connection contract. The terms and conditions of the standard customer connection contract are set out in Annexure A of the Electricity Industry Code. The standard contract cannot be utilised by generators. Clause 5.3 of the standard contract requires the DNSP to provide, install and maintain equipment for the provision of customer connection services at the premises in a manner which is safe and in accordance with the electricity legislation. Clause 7.3 requires the customer to pay for the customer connection services and clauses 10.1-10.3 of this standard contract set out the manner by which connection costs will be levied with a distinction drawn between contestable and non-contestable customers. Contestable customers are required to pay the DNSP the cost of connection with that amount determined from time to time in accordance with all applicable instruments. The connection costs for non-contestable are recovered by the retail entity.

C.2.1.2.2. Negotiated contracts

Section 40C of the Electricity Act enables a customer and a DNSP to contract on terms different to the standard contract, however, such a contract must not be inconsistent with the Act. Section 40D further requires the DNSP to connect a customer’s premises or electrical installation on fair and reasonable terms. Division 4 of the Electricity Regulations state that the following do not constitute unfair and unreasonable terms:

- Alternative methods for charging (section 63);
- The use of a negotiated contract (section 64);
- Differing security (section 65); and
- Different terms if the circumstances required for providing the services are different; and the terms reasonably reflect the impact on the entity of the differences between the customers or types of customers or different circumstances (section 66);64 and

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64 The different circumstances include differences in: the nature of the plant or equipment required to provide the services; geographical and electrical locations of the relevant connections; periods for which the services are to be provided; the electricity supply capacity required to provide the services; the characteristics of the relevant load or generation; and the performance characteristics at which the services are to be provided.
The mere imposition of different capital contributions is not unfair or unreasonable if the capital contributions are worked out under a capital contribution policy approved by the jurisdictional regulator.

Apart from the requirement that negotiated contracts not be inconsistent with the Electricity Act and the requirement that the DNSP connect a customer’s premises on fair and reasonable terms, there are no apparent instruments which regulate the way in which negotiations must take place. That is, there are no specified timeframes within which the negotiations and exchange of information must take place.

C.2.1.3. Arbitration framework

Chapter 5 of the Electricity Act sets out the role of the Chief Executive of the Department of Energy when a dispute arises under the Act in relation to the performance of a function or obligation or exercise of a power under this Act. The provisions contained within this chapter allow the regulator to refer the dispute to a mediator or an arbitrator if the customer makes such a request (section 119). Provisions relating to the mediation process and the powers of the mediator are contained in sections 120ZD to 120ZDO while the provisions relating to the arbitration process and powers of the arbitrator are contained in sections 120ZP to 120ZZG.

The dispute resolution mechanism contained in Chapter 5 does not extend to disputes surrounding the definition of fair and reasonable terms and conditions. Disputes of this form are subject to the dispute resolution mechanism contained in Part 4 of the Electricity Regulations. This mechanism allows the regulator to resolve the dispute if a party to the dispute makes such a request.

C.2.2. Connection charges and capital contributions

C.2.2.1. Regulation of connection charges

Connection services are currently deemed to be prescribed services and as such form part of the revenue cap. The QCA’s approach to determining whether a service is an excluded service requires a DNSP, or any other interested party, to demonstrate that there is effective competition for the service. According to the QCA’s 2005 Final Determination competition will be effective if the DNSP lacks substantial influence in the market and is unable to raise prices above the efficient costs of supply or earn an excessive rate of return based on efficient operation and investment.

The method by which prices are set for these services are set out in the DNSP’s Pricing Principles Statement which must be approved by the QCA.

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65 Queensland Competition Authority, Final Determination – Regulation of Electricity Distribution, April 2005, pg. 54.
The connection charges levied by both Ergon and Energex draw a distinction between standard asset customers (SAC)\(^66\) and connection asset customers (CAC),\(^67\) embedded generators (EG) and individually calculated customers (ICC).\(^68\)

For SACs the connection charge is based on the average cost of connection assets for all standard asset customers. To the extent that a SAC’s cost of connection (including a contribution toward shared network assets) exceeds the average the DNSP may require a capital contribution.

The connection charge for CACs, EGs and ICCs is based on the cost of the dedicated connection assets with the charge generally recovered through a site specific network charges. A capital contribution may used in place of a site specific network charge if negotiated by the parties.

The regulatory treatment of capital contributions and the principles underlying these contributions are set out in the following section.

C.2.2.2. Capital contributions

A DNSP’s ability to require the payment of a capital contribution (either monetary or in-kind) for connection (including the costs incurred, or to be incurred, in extending or increasing capacity) may be implied from both section 34(1)(b) and 31(d)(2)(iii) of the Electricity Regulation which enable the DNSP to refuse to connect or otherwise limit its obligation to connect if a customer fails to make a capital contribution towards the costs incurred, or to be incurred, by the DNSP in:
- providing the dedicated connection assets;
- extending the network; or
- augmenting the network to increase its capacity.

In accordance with section 66 of the Electricity Regulations, the capital contribution required by a DNSP may vary across alternative customers if the DNSP’s capital contribution policy (contained within the DNSP’s Pricing Principles Statement) is approved by the jurisdictional regulator, the QCA. The capital contribution policy sets out, amongst other things, the principles used to determine:
- the alternative ways in which standard asset customers, connection asset customers, DGs and individually calculated customers will be treated.
- the required monetary or in-kind capital contributions;
- the manner by which capital contributions may be shared;

\(^{66}\) An individually calculated customer is a customer that has a consumption level greater than 40 GWh per annum at a single connection point; or where a customer’s circumstances mean that the average shared network charge becomes meaningless or distorted.

\(^{67}\) A connection asset customer is a customer that has a consumption level greater than 4 GW.h per annum at a single connection point; or where a customer has a dedicated supply system with significant connection assets.

\(^{68}\) A standard asset customer is one that has an annual electricity consumption below 4 GWh per annum.
the way in which capital contributions will be reflected in prices; and

the treatment of new developments.

Each of these principles is founded on the economic efficiency and equity objectives which according to the QCA require the following:

- To meet the economic efficiency objective, capital contributions should only cover any shortfall between the present value of additional distribution charges expected to be paid by the new customer over the life of the assets and the incremental cost of connecting that customer. This approach also ensures that existing users are no worse off following the connection of a new user because the expected network revenue from the new customer (in the form of additional charges and/or capital contributions) will cover the incremental cost of supply.

- To meet the equity objective, it is reasonable to expect each customer, in addition to their incremental costs of connection, to make some contribution to shared assets. Typically, for large contestable customers with individually calculated charges, the customer’s actual connection costs are fully recovered through their distribution charges. However, because franchise customers and smaller contestable customers (Standard Asset Customers) pay average charges, they must meet any additional connection costs as a separate capital contribution.

The following table provides a summary of Ergon’s and Energex’s capital contribution policies which have been approved by the QCA.

In addition to these principles both Ergon and Energex have policies in place relating to the treatment of developers. Ergon’s policy states that developers are responsible for 100% of the cost of providing infrastructure including reticulation, extension works and shared network augmentation and are assumed to pass these assets through to Ergon as an in-kind capital contribution with the value of this contribution then recognised in the SAC allocated costs. Once the assets are passed through to Ergon it becomes responsible for operation and maintenance of assets and assets pass through as in-kind contribution. It is assumed that the costs incurred by the developer are passed onto buyers of the premises within the development and thus developers do not receive the benefit of cost sharing.

Historically, Energex’s policy in relation to developers involved it supplying transformers, cables and overhead materials up to a maximum value per lot with all other assets and services provided by the developer. Energex is now in the process of transitioning to a similar scheme to Ergon under which the developer will be responsible for 100% of the cost of providing the infrastructure. Energex will, however, make a contribution to the cost of the works required to augment the feeder and shared network outside the development and the backbone network within development where the standard it requires exceeds that which is required to supply the development.
**Table C.3: Queensland capital contribution policies**

<table>
<thead>
<tr>
<th>Issue</th>
<th>Ergon</th>
<th>Energex</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assets</td>
<td>Dedicated connection assets and upstream shared network assets.</td>
<td></td>
</tr>
<tr>
<td>Treatment of alternative users</td>
<td>ICCs, CACs and EGs connection costs included in the network charge which includes site specific connection costs.</td>
<td>SACs pay capital contribution on top of DUOS tariff if average distribution price for network would not be sufficient to recover the full cost of the connection. Prepayment of expected revenue shortfall made through a capital contribution.</td>
</tr>
<tr>
<td>Formula used to calculate capital contribution for SAC</td>
<td>( CC = \text{ICCS} - \left( IR_{n=20} - (IR_{n=20} \times X%) \right) ) where ( CC = ) capital contribution, ( \text{ICCS} = ) Incremental Cost – customer specific portion of the Project Cost, ( IR_{n=20} = ) Present value of incremental revenue over twenty year period directly attributable to the new connection, ( X% = ) percentage contribution to shared network cost which differs according to zone</td>
<td>( CC = \text{ICCS} + \text{ICSN} - \left( IR_{n=20} - \text{SNC}(10%) \right) ) where ( CC = ) capital contribution, ( \text{ICCS} = ) customer specific incremental costs based on actual cost of dedicated assets and additional costs incurred in the shared network as a direct result of the connection, ( \text{ICSN} = ) incremental costs in the upstream (shared) network directly attributable to the new connection, ( IR_{n=20} = ) Present value of incremental revenue (based on DUOS) over twenty year period directly attributable to the new connection, ( \text{SNC}(10%) = 10% ) attribution of incremental revenue (( IR_{n=20} )) to the costs of the existing shared network to account for the contribution to the shared network</td>
</tr>
<tr>
<td>Treatment of capital contributions in price</td>
<td>Capital contributions (monetary and in-kind) deducted from costs allocated to this group and assets rolled into regulatory asset base.</td>
<td></td>
</tr>
<tr>
<td>Cost Sharing - Term</td>
<td>Subsequent customers may be required to compensate previous customers if the subsequent customer connects within five years from the date of the initial customer. The initial contribution levels reduced to zero over five years.</td>
<td>Subsequent contributions to the initial extension to be calculated in proportion to customer size based on forecast DUOS revenue from DUOS charges applicable to that customer class, no sharing permitted under Rural Subsidy Scheme, amounts less than $100 not refunded.</td>
</tr>
</tbody>
</table>
Appendix D. South Australia

D.1. Network planning

The instruments governing the planning arrangements in South Australia include:

- the *Essential Services Commission Act 2002*;
- the *Electricity Act 1996*; and
- the Electricity Industry Guideline Number 12: Demand management For Electricity Distribution Networks (2003).  

<table>
<thead>
<tr>
<th>Table D.1: South Australia network planning regulatory instruments</th>
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</thead>
<tbody>
<tr>
<td>Instrument</td>
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<tr>
<td>------------</td>
</tr>
<tr>
<td>Legislation</td>
</tr>
<tr>
<td>Licence</td>
</tr>
<tr>
<td>Guideline</td>
</tr>
</tbody>
</table>

Electricity Industry Guideline Number 12 (Guideline 12) provides guidance on how ETSA utilities should meet its licence obligation and thus failure to comply with this document may be treated as a breach of its licence.

D.1.1. Periodic planning and reporting requirements

The DNSP in South Australia (ETSA Utilities) must publish an annual Electricity System Development Plan (ESDP). The ESDP must include:

- an overview of ETSA Utilities planning criteria;
- an overview of the complete distribution network, and specific regional development plans;
- five years of historical and forecast load data;
- details of expected network constraints for the next three years; and

\[\text{id:69, name: "ESCOSA is conducting a review of this guideline and published a draft decision in February 2007"}, \text{id:70, name: "ESCOSA is conducting a review of this guideline and published a draft decision in February 2007"} \]
information to allow customers and interested parties to assess whether they might be able to assist in addressing this complaint.

D.1.2. Consideration of non-network alternatives

The *Electricity Act 1996* requires that conditions be imposed in distribution licences to conduct investigations on the cost effectiveness of implementing demand management strategies that may permit proposed expansions of the network to be avoided or postponed, and to prepare and publish reports relating to these conditions.

Because the NER only require DNSPs to consider non-network alternatives for projects greater than $10 million, ESCOSA has developed its own framework requiring ETSA Utilities to consider projects below this level in order to meet its licence condition.71

Under the requirements set out in Guideline 12, ETSA Utilities must consider non-network solutions for all network projects that meet a “reasonableness test” – essentially all projects where the estimated capital cost to relieve the constraint is at least $2 million.

ESCOSA explains that this $2 million value was selected on the basis that it would cover a reasonable number of projects each year where alternative strategies to relieve demand could be considered, while also not imposing undue costs on the DNSP or issuing such a large number of requests for proposals (RFP) that respondents would not be able to give them due consideration.

D.1.3. Case-by-case project assessment and consultation

For all projects that pass the reasonableness test ETSA must issue a RFP seeking options from interested parties about possible non-network solutions to overcome a system constraint.

ETSA Utilities must keep a register of interested parties, whom it advises regarding the issue of a RFP. The RFP must be issued at least 38 weeks prior to the forecast date for which the system support is required and must allow proponents at least 25 weeks to submit proposals. Guideline 12 sets out the detailed requirements that need to be included both in the RFP and in the proponent’s response. A proponent may submit a draft proposal up to 12 weeks prior to the due date for submissions in order to confirm that the draft proposal conforms to the requirements of the RFP. ETSA Utilities must respond at least six weeks prior to the end of the submission period.

ESCOSA recently published a final decision on its review of Guideline 12. The report responds to issues raised by industry participants and considers what improvements could be made to enhance the prospect for demand management. The main recommendation flowing from this decision concerns streamlining the process undertaken by ETSA Utilities in requesting proposals from interested parties. ESCOSA concluded that there was little point in issuing RFPs for network augmentation projects where a reduction in demand from demand management initiatives is unlikely, or where such demand reductions are likely to be very expensive. Under the revised Guideline ETSA will be required to screen all relevant

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71 See ESCOSA: Final Decision, Review of Electricity Industry Guideline 12: Demand Management for Electricity Distribution Networks
proposals (those where a network solution is expected to cost more than $2 million) to
determine whether a non-network project is likely to be economically viable or technically
feasible. Only for those projects that pass this new 'reasonableness test' - i.e. have reasonable
chance of success - will ETSA Utilities be required to publish a comprehensive RFP. ETSA
Utilities will still need to publish the results of its screening process and where appropriate
explain why it did not publish an RFP. Some of the areas where ESCOSA suggest an RFP
might not be appropriate include:

- new developments, where dedicated assets are required to supply new customers;
- where network augmentation is required for quality of supply reasons or the age of the
  infrastructure;
- new large spot loads where there is insufficient time to investigate and implement a
demand side response; and
- where a constraint stems from a known single or dominant group of customers with
  whom demand side solutions can be discussed without issuing an RFP.

Where a project passes this reasonableness test an RFP should be issued within three months.
A period of six months should be allowed for non-network proposals, and a further three
months for ETSA Utilities to assess such proposals and publish its results.

ESCOSA stresses that a RFP should be as user-friendly as possible and contain all relevant
information, including:

- details of the type of demand side initiatives investigated as part of reasonableness test
  those might be possible;
- details of the current supply arrangements, including a map of the area, capacity and
demand forecasts;
- estimated cost of preferred network solution;
- details of the required demand management characteristics, including an indication of the
  financial incentive available for a permanent and temporary reductions in demand (in
  $ per KVA);
- details of the customer base; and
- details of the evaluation and selection criteria.

D.1.4. Evaluation of options - economic test

The Evaluation Process must comply with the Regulatory Test and evaluate all options
(network and non-network) and rank them according to the total annualised cost incurred in
providing the system support. This includes the cost incurred to ETSA Utilities plus the cost
or benefit of changes to distribution or transmission losses. This cost must be adjusted to
account for the relative risk of each option.

ETSA Utilities has to publish the result of all of the proposals.
D.1.5. Regulatory oversight or dispute resolution

ETSA Utilities is required to publish a compliance report annually, setting out all network projects or extensions that it has considered in the previous year, along with an explanation of the consultation process it followed and the specific demand management proposals it considered.

There is no mechanism for a proponent of a particular option to dispute the outcome of an evaluation by ETSA Utilities, or the method adopted for relieving a system constraint.

D.2. Network connections and connection charges

The current regulatory arrangements in South Australia pertaining to connection applications and the payment of connection charges are governed by a combination of the NER and state-based legislation.

In accordance with the jurisdictional derogation in Rule 9.28.2 ESCOSA is responsible for the regulation of access to any distribution network located in South Australia. ESCOSA has also been accorded responsibility for ruling on the fairness and reasonableness of an offer under Rule 5.3.6(c). If a dispute regarding access arises involving two or more Registered Participants, and resolution is not reached within 5 business days,\(^2\) then the matter must be referred to ESCOSA to act as the Adviser. If ESCOSA thinks it appropriate, it may also act as the dispute resolution panel under Chapter 8 of the NER, as long as arrangements are made so that no party is adversely affected by it doing so having previously acted as the Adviser. If ESCOSA is unable or unwilling to do so it must appoint a panel in accordance with Chapter 8.

The following table provides a summary of the state-level legislation and regulatory instruments pertaining to the regulation of connections in South Australia.

<table>
<thead>
<tr>
<th>Instrument</th>
<th>Title</th>
<th>Relevant provisions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Legislation</td>
<td>Electricity Act 1996</td>
<td>Provides some definitions, requirement for provision to refer to ombudsman (s 23k)</td>
</tr>
<tr>
<td>Legislation</td>
<td>Essential Services Commission Act 2002</td>
<td>Accords ESCOSA the power to maintain codes relating to regulated industries (s 28)</td>
</tr>
<tr>
<td>Regulation</td>
<td>Electricity (General) Regulations 1997</td>
<td>Describes which embedded generators are exempt from licensing (reg 6)</td>
</tr>
<tr>
<td>Code</td>
<td>Electricity Distribution Code 2006</td>
<td>Provides majority of material guidance relating to obligations to connect, connection agreements and capital contributions</td>
</tr>
<tr>
<td>Relevant regulatory</td>
<td>Electricity Distribution</td>
<td>Sets out principles for pricing of both prescribed and excluded services</td>
</tr>
<tr>
<td>decisions</td>
<td>Price Determination 2005</td>
<td></td>
</tr>
</tbody>
</table>

\(^2\) Or another period agreed to by all parties.
The remainder of this appendix provides an overview of the network connection arrangements prevailing in South Australia and the role of capital contributions within this process.

**D.2.1. Network connection arrangements**

Pursuant to section 28 of the *Essential Services Commission Act 2002*, ESCOSA maintains the Electricity Distribution Code (Code) which contains most of the regulatory guidelines applying to connections.

**D.2.1.1. Obligation to connect**

Section 1.4 of the Code outlines the requirements for a DNSP to connect a customer’s supply address. It provides required timeframes for both previously connected (section 1.4.1) and new (section 1.4.2) supply addresses. In accordance with section 1.4.3 a DNSP may require a customer to satisfy some, or all, of a series of administrative\(^{73}\) and safety\(^{74}\) conditions and pay for augmentations or extensions.

**D.2.1.1.1. Connection of DGs**

Chapter 2 of the Code relates to the connection of DGs and applies to both small,\(^{75}\) large (which are not required to be a Code Participant under the National Electricity Code)\(^{76}\) and any DGs exempt under regulation 6 of the Electricity (General) Regulations 1997 from the requirement to be licensed as a generator under the *Electricity Act 1996*.

Provisions within this chapter of the Code require the DG to comply with technical requirements which are specified within the Code.

**D.2.1.2. Connection agreements**

Section 1.1.1 of the Code provides for the use of a standard customer contract or a negotiated customer contract.

**D.2.1.2.1. Standard contracts**

Part B of the Code contains a pro-forma standard contract which sets out the terms and conditions that must be used by the DNSP.

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\(^{73}\) Such as nominating a retailer, paying relevant fees and charges and providing estimates of load.

\(^{74}\) Such as ensuring access to the meter and electrical installation, verification of certificates of compliance.

\(^{75}\) An embedded generator which owns, operates or controls an embedded generating unit that satisfies AS4777.

\(^{76}\) An embedded generator other than a small embedded generator.
D.2.1.2.2. Negotiated contracts

Section 1.1.1(b) of the Code states that a DNSP may enter into negotiated connection and supply contracts. For large customers\(^{77}\) section 1.1.1(b) simply states that the terms are to agreed with that customer while the terms agreed with small customers must be reviewed by ESCOSA.

D.2.1.2.3. DG contracts

Section 2.3(a) of the Code states that a DNSP must only agree to provide connection services to a small DG in accordance with a standard connection agreement for small DGs developed by the DNSP. This agreement must be approved in writing by ESCOSA before use. In accordance with section 2.3(c) ESCOSA may require or perform amendments to a submitted standard connection agreement before approval.

Section 2.3(f) of the Code provides for negotiated connection agreements with small DGs on fair and reasonable terms, provided that that agreement is approved by ESCOSA. Section 2.4 states that large DGs must only be connected to the DNSP’s network in accordance with terms and conditions of a connection agreement which are fair and reasonable and agreed to by that large DG. No definition of ‘fair and reasonable terms’ is provided.

D.2.1.3. Arbitration framework

Section 1.3.2 of the Code requires a DNSP to submit a proposed dispute resolution mechanism to ESCOSA for approval within 20 business days of receiving a distribution license.

D.2.2. Connection charges and capital contributions

D.2.2.1. Regulation of connection charges

According to the 2005 Electricity Distribution Price Review (EDPR) connection services are excluded services. Pricing principles for excluded services are contained within the EDPR. These principles state that:

- prices must be fair and reasonable, including consideration by ETSA Utilities of cost reflectivity and overall profitability in relation to the total grouping of excluded distribution services;\(^{78}\)

- the annual price movement for any particular excluded service should be restricted to no more than CPI+10% unless otherwise approved by ESCOSA;\(^{79}\)

---

\(^{77}\) Any customer other than a small customer, which is defined as a customer with an annual electricity consumption of less than 160MW.h under regulation 4B of the Electricity (General) Regulations 1997 as an interpretation of section 4 of the Electricity Act 1996.

\(^{78}\) This latter provision is designed to factor in the existence of cross subsidies in excluded services.

\(^{79}\) This principle is designed to stop any large price shocks resulting from unwinding of cross subsidies.
if effective market competition exists for an excluded service, market prices will be
deemed fair and reasonable, however, ETSA Utilities must demonstrate the existence of
this effective competition to ESCOSA; and

in the event of a dispute, ESCOSA will determine whether an amount proposed to be
charged by ETSA Utilities in respect of an excluded service complies with the pricing
principles.

D.2.2.2. Capital contributions

Chapter 3 of the Code sets out procedures for establishing new or modifying existing
connections that require augmentations or extensions. It provides that a DNSP is allowed to
charge for such connections provided that the offer is based on the most efficient and
technically feasible solution. Section 3.4 states that a customer in such a situation may issue
a call for tenders for the design and construction of the new assets and provides various
requirements on the DNSP to expedite this process. Section 3.5 contains the following
formula to be used when calculating the capital contribution payment:

\[
CP = (C + E + A + CC) - R
\]

Where CP = customer payment, C = cost of connection assets, E = cost of extension, A =
customer’s allocation of augmentation, \(CC = \) customer’s contribution to upstream
customers, and R = distributor’s rebate.

D.2.2.2.1. DG

Sections 2.5, 2.6 and 2.7 of the Code state that connection, extension and augmentation
charges for DG must be calculated as an excluded service charge in accordance with
ESCOSA guidelines (sections 2.5 and 2.6).

Notably, section 2.7(a) states that a DNSP must not charge a small DG for any augmentation
required as a result of the connection of their units to the distribution network.

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80 An allowance exists for augmentation that will not be charged to the customer, discussed in Section 3.6 of the Code.
The standard allowance listed in section 3.6.3 (d) is 90kVA.

81 This allows for a customer contributing towards amounts paid by an upstream customer for an extension. This must
occur within 7 years of the extension taking place and is discussed in Section 3.8 of the Code.

82 Section 3.7 of the Code outlines the calculation of this rebate to offset costs, broken down by residential and non-
residential, based on an average measure of expected DUOS charges. For residential customers it is $3000; non-
residential customers have a formula which gives the rebate as the higher of $3000 or $1200 (for new connections, $0 if
a modification of an existing connection) + 3 x expected annual DUOS charges.
Appendix E. Australian Capital Territory

E.1. Network planning

E.1.1. Periodic planning and reporting requirements

Aside from the requirements that exist in the NER, there are no additional state based regulations requiring the DNSP to publish further details of its planning arrangements.

E.1.2. Consideration of non-network alternatives

The DNSP is only required to consider non-network alternatives in so far as it is required to do so under the NER.

E.2. Network connections and connection charges

The current regulatory arrangements in the Australian Capital Territory pertaining to connection applications and the payment of connection charges are governed by a combination of the NER and state-based legislation. No relevant derogations relating to the Australian Capital Territory are provided in the NER.

Table E.1: Australian Capital Territory connection regulatory instruments

<table>
<thead>
<tr>
<th>Instrument</th>
<th>Title</th>
<th>Relevant provisions</th>
</tr>
</thead>
</table>
| Legislation | Utilities Act 2000 | Obligation of a DNSP to connect in accordance with licence obligations (s79)  
Provision made for standard customer contracts (s 27 and 92)  
Provision made for negotiated connection contracts (s 95)  
Terms of standard contract to be approved (ss 87 and 88)  
Ability to recover capital contributions (s 101)  
Provision made for the ICRC to develop industry codes and for technical codes to be developed (Parts 4 and 5) |
| Code | Electricity Network Use of System Code (2000) | Obligation for DNSP and a retailer to enter into a network use of system agreement setting out the terms upon which the connection and use of system services will be provided (s 1)  
DNSP and supplier to negotiate in good faith and on reasonable terms (s3.2)  
DNSP must offer terms that comply with the minimum standards in the National Electricity Code and standards set out in Electricity Distribution (Supply Standards) Code unless otherwise negotiated in a negotiated customer contract (s 3.3)  
Disputes resolved through Chapter 8 of the Electricity Code (s 3.4) |
Treatment of rural and uneconomic loads (ss 3.5 -3.6) |
| Relevant regulatory decisions | Prices for Electricity Distribution Services - Final Decision –2004 | Defines connection services as a prescribed service.  
Sets out treatment of capital contributions in regulatory model. |
The remainder of this appendix provides an overview of the network connection arrangements prevailing in the Australian Capital Territory and the role of capital contributions within this process.

E.2.1. Network connection arrangements

E.2.1.1. Obligation to connect

In accordance with section 79 of the Utilities Act 2000 (Utilities Act) a DNSP must, on application by a person:

- connect the premises to which the application relates;
- vary the capacity of the connection to which the application relates; and
- allow the connection, or variation of the capacity of the connection, by another accredited party if requested by the applicant.\(^{83}\)

The provision of any of these services must be undertaken in accordance with the standard customer contract.

The Consumer Protection Code (2000) draws a distinction between franchise customers, small non-franchise customers and large non-franchise customers. A non-franchise customer is defined in the Utilities Act as a person who uses 160MWh of electricity or more at particular premises in a particular year.

The DNSP’s obligation to provide connection services to franchise customers is defined in clause 16.1 of the Consumer Protection Code which states that a licensed DNSP must provide the service requested within a reasonable time. This obligation may, however, be limited by provisions within clause 16.2 of the Consumer Protection Code which includes the failure of an applicant user to pay connection charges or to make a capital contribution.

E.2.1.2. Connection agreements

Section 27 of the Utilities Act provides for the use of either a standard customer contract or a negotiated customer contract.

E.2.1.2.1. Standard contracts

Sections 89 to 91 of the Utilities Act require the Independent Competition and Regulatory Commission (ICRC) to approve the terms incorporated within a standard customer contract. The ICRC may only approve the terms if it is satisfied that the terms are consistent with the conditions of the DNSP’s licence, the terms are fair and reasonable, and the charges payable are consistent with a price direction by the ICRC. If the ICRC does not approve the terms then it may determine the terms itself. Part 3 of the Consumer Protection Code set out the minimum provisions to be contained in the standard customer contract. The Electricity

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\(^{83}\) The work undertaken by another party cannot extend to augmentation, relocation or other alteration of the DNSP’s network.
Distribution (Supply Standards) Code prescribes minimum technical standards that the standard customer contract must incorporate.

### E.2.1.2.2. Negotiated contracts

A DNSP and user may also enter into a negotiated customer contract (section 95 of the Utilities Act). However, a negotiated contract will be unenforceable if the terms are inconsistent with the conditions of the DNSP’s licence or the requirements set out in the Utilities Act, industry or technical code. The Utilities Act in its current form does not specify the timeframes within which a negotiation must take place nor does it require any exchange of information between the negotiated parties. Clause 24 of the Consumer Protection Code does, however, require a cooling off period of ten days. In accordance with the Electricity Distribution (Supply Standards) Code the DNSP and user will not be bound by the minimum technical standards contained in the Code and may agree on alternative supply standards (section 3.1).

### E.2.1.3. Arbitration framework

Section 185(1)(d) of the Utilities Act allows a user to register a complaint with the Essential Services Consumer Council regarding any alleged contravention of a DNSP’s obligation under the Act. This provision appears to encompass the obligation to provide a connection service in under section 79 of the Act which must be undertaken in accordance with the standard customer contract. Part 12 of the Utilities Act set out the procedures to be followed by the Essential Services Consumer Council in relation to such a complaint. It is unclear whether the complaints procedure extends to negotiated customer contracts.

### E.2.2. Connection charges and capital contributions

#### E.2.2.1. Regulation of connection charges

In the period up to April 2004, restrictions prevented any party other than the DNSP from providing connection services and thus connection services were, in the ICRC’s March 2004 “Investigation into prices for electricity distribution services in the ACT”, defined as prescribed services and as such formed part of the revenue cap.\(^{84}\) \(^{85}\)

The method by which prices are set for these services are set out in ActewAGL’s Pricing Strategy Statement which was approved by the ICRC. Within this Statement ActewAGL noted that connection costs rise with the size of the consumer and so are recovered in the

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\(^{84}\) ICRC, Prices for electricity distribution services in the ACT, March 2004, pg. 14.

\(^{85}\) In a review undertaken for the Australian Capital Territory’s Treasurer in April 2004 (ICRC, Review of contestable electricity infrastructure works, April 2004, pg. 35) the ICRC recommended that restrictions on contestability be lifted for those infrastructure services where:

- the work can be isolated safely and not impede other users;
- the user is required to make a capital contribution; and
- the user’s share of the cost is over $10,000 and the service.

Within its recommendation the ICRC noted all the legislative changes that would be required to remove the restrictions, however, these changes do not appear to have been made at this time.
energy and demand related charges. While the connection charges for retail customers are relatively standard they are less so for DGs, developers and large consumers and thus the costs to these customers are generally subject to negotiation. The Pricing Statement does, however, state that DGs will be required to pay the network connection charge.

The regulatory treatment of capital contributions and the principles underlying these contributions are set out in the following section.

E.2.2.2. Capital contributions

Section 101 of the Utilities Act allows a DNSP to impose a capital contribution charge on a user for the development or augmentation of its network to enable services to be made to new development or to vary the capacity of connections to its network. The capital contribution charge must, however, conform with the Electricity Network Capital Contributions Code (2001). This Code allows a DNSP to impose a capital contribution charge upon a user for the development or augmentation of the network (section 3.1) if:

- the requirements of the user exceed the basic standard infrastructure\(^\text{86}\) which the DNSP must install at no charge. The capital contribution charge payable by the customer must not exceed the additional costs incurred by the DNSP in providing the alternative infrastructure (section 3.3);

- the customer is a rural customer in which case a DNSP may require the payment of a capital contribution equal to the difference between the costs incurred in connecting the rural customer and the average cost of connecting a residential customer in an urban area (section 3.4); and

- the load is uneconomic such that the over the life of the additional network assets required to connect the user, the costs would exceed the network revenue received from that user. The capital contribution in this case may be set at the full cost of the work (section 3.5).

The Code also states that any assets that are subject to a capital contribution will not confer any ownership rights on that party. The Code does not refer to any cost sharing mechanisms for subsequent users that make use of the assets funded through the capital contribution. The Code also contains no reference to the formula to be used when calculating the capital contribution charge.

Capital contributions are recognised in the revenue cap by reducing the capital expenditure rolled into the regulated asset base by the value of the capital contribution.

Any disputes relating to capital contributions must be registered with the Essential Services Consumer Council (Section 185(1)(f) of the Utilities Act all) Part 12 of the Act sets out the procedures to be followed by the Essential Services Consumer Council in relation to such a complaint.

\(^{86}\) The basic standard infrastructure includes: the construction of extension assets from the existing boundary to the land being developed; the provision of a service connection up to a maximum of 22 metres from the distribution system to the premises if overhead assets or 8 metres if underground assets.
Appendix F. Tasmania

F.1. Network planning

Table F.1: Tasmania network planning regulatory instruments

<table>
<thead>
<tr>
<th>Instrument</th>
<th>Title</th>
<th>Relevant Provision</th>
</tr>
</thead>
<tbody>
<tr>
<td>Legislation</td>
<td>Electricity Supply Industry Act 1995</td>
<td>Requires DNSP to be licensed also requires licensee to comply with Electricity Code (Section 22(1)(e))</td>
</tr>
<tr>
<td>Code</td>
<td>Tasmanian Electricity Code</td>
<td>Sets out the requirement that Aurora provide annual plan to the regulator</td>
</tr>
</tbody>
</table>

The Tasmanian Energy Regulator publishes and maintains the Code, which sets out the detailed arrangements for Regulation of the electricity industry and is enforceable under the Electricity Supply Industry Act 1995.

F.1.1. Periodic planning and reporting requirements

Under the Tasmanian Electricity Code, a DNSP must submit an annual Distribution System Planning Report to the Regulator, detailing how it plans to meet predicted demand and improve reliability for customers over the next five years.

In relation to the planning of the distribution network the report must include the following:

- the historical and forecast demand from, and capacity of, each transmission connection site;
- an assessment under credible contingency of the magnitude, probability and impact of load at risk for each transmission connection site;
- an assessment under credible contingency of the magnitude, probability and impact of load at risk for the transmission system configuration;
- an assessment under credible contingency of the magnitude, probability and impact of load at risk for designated regions or supply areas;
- the DNSP’s planning standards;
- a description of feasible options for meeting forecast demand including opportunities for DG and demand management;
- where a preferred option for meeting forecast demand has been identified, a reasonably detailed description of that option, including estimated costs; and
- the availability of contributions from the DNSP to DG or customers to reduce forecast demand and defer or avoid augmentation of the DNSP’s distribution system.

Aurora Energy does not appear to publish this report on their website.

F.1.2. Consideration of non-network alternatives

The annual planning report requires the DNSP to identify feasible options for embedded generation and demand side management as well as provide an estimate of the price at which
this would need to be achieved. It does not, however, require Aurora Energy to republish
details on non-network solutions for individual network constraints when planning reaches an
advanced stage.

**F.1.3. Case-by-case project assessment and consultation**

Aside from the requirement that the DNSP identify where potential non-network solutions
could arise, there are no requirements for a formal notification process or request for
proposals where a specific augmentation is proposed to relieve a network constraint.

**F.1.4. Evaluation of options - economic test**

There is no requirement under state legislation for any regulatory test to be conducted, only
those requirements that already exist under the NER.

**F.1.5. Regulatory oversight or dispute resolution**

There is no formal dispute mechanism if a party disagrees with the planning process
implemented by the DNSP.

**F.2. Network connections and connection charges**

The current regulatory arrangements in Tasmania pertaining to connection applications and
the payment of connection charges are governed by a combination of the NER and state-
based legislation. No relevant derogations relating to Tasmania are provided in the NER.
The following table provides a summary of the state-level legislation and regulatory
instruments pertaining to the regulation of connections in Tasmania.

<table>
<thead>
<tr>
<th>Instrument</th>
<th>Title</th>
<th>Relevant provisions</th>
</tr>
</thead>
</table>
| Legislation| Electricity Supply Industry Act 1995       | Regulator (OTTER)'s right to provide and enforce Tasmanian Electricity Code (s 6(1)(a))
|            |                                            | Obligation to connect (s 25(1)(a)) Dispute resolution (s 45)                        |
| Code       | Tasmanian Electricity Code 2005            | Capital contributions (s 6.6)                                                       |
| Relevant regulatory decisions | Investigation of Maximum Prices for Electricity Distribution Services on Mainland Tasmania: 2007 | Connections a declared service (s 2.1.1)                         |
|            | Declaration of Distribution Services to be Investigated and Terms of Reference for the Price Investigation |                                                                 |

The remainder of this appendix provides an overview of the network connection
arrangements prevailing in Tasmania and the role of capital contributions within this process.
F.2.1. Network connection arrangements

Chapter 5 of the Tasmanian Electricity Code previously contained provisions relating to connection but this chapter was deleted in anticipation of Tasmania's entry into the NEM and the adoption of the NER. Accordingly, there are currently no jurisdictional specific provisions relating to connection agreements and it has been assumed that the connection agreement process set out in Rule 5.3 of the NER currently applies.

F.2.1.1. Obligation to connect

Section 25(1)(a) of the Electricity Supply Industry Act 1995 (Electricity Supply Industry Act) makes it a condition of an exclusive retail license that a retailer provide electricity supply services to any customer who requests it (on reasonable terms and conditions). As Aurora Energy Pty Ltd is the sole DNSP and retailer in Tasmania this amounts to a DNSP obligation to connect.

F.2.1.1.1. DGs

In accordance with section 8.7.1 of the Tasmanian Electricity Code a DNSP must have in place a procedure, approved by the Office of the Tasmanian Energy Regulator (OTTER), to deal with connections of DGs. It stipulates that a contract is required; section 8.7.1(c) lists some specific items that must be dealt with, including charges, conditions and procedures for dispute resolution. Section 8.7.1(e) also contains a requirement that the parties negotiate in good faith.

F.2.1.2. Arbitration Framework

Section 8.3.1 of the Code states that a DNSP must provide its customers with a customer charter, approved by OTTER, which includes a description of how to make a complaint to the Energy Ombudsman. Section 8.4 contains more detail on how a DNSP must handle a complaint, including escalation to a higher management level and informing the customer of their right to refer their complaint to the Ombudsman.

F.2.2. Connection charges and capital contributions

F.2.2.1. Regulation of connection charges

Connection services are currently a declared service in Tasmania and are therefore subject to regulation.

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F.2.2.2. Capital contributions

Section 6.6 of the Code states that a DNSP may require capital contributions as a prudential requirement. The nature of these is left open to negotiation and expressly may include non-cash asset contributions. Aurora Energy has published a procedure, entitled ‘Overhead Electricity Supply at Low Voltage” which sets out its approach to connection charges and capital contributions.

Aurora Energy’s policy is to provide a service connection equal to a single span from the distribution network to the customer’s property, the connection fuse and necessary meters. Aurora Energy provides subsidies for service connection, transformer installation and the extension of a high or low voltage asset along a public road. The value of these subsidies is set out in Attachment 1 of the procedure and ranges from $430-$6,400 for service connections, $5,100-$21,800 for transformer installations and $7,500 for extensions along a public road.

Where a user’s requirements deviate from the standard criteria (ie, when Aurora is required to convert its line from a 1 to a 3-phase) the user bears the cost of these differences. Aurora’s procedure also requires the user to pay all Aurora’s costs in obtaining an easement that is located on another party’s property. Developers are also required to pay any additional costs above the subsidies including a capital contribution towards a development main.

Aurora’s procedure also states that where more than one user is to be supplied by an extension or augmentation, any capital contribution required from the users may be apportioned between them as mutually agreed by the users and Aurora. Aurora Energy may require the payment of this contribution before work is commenced.
Appendix G. Network planning provisions in the NER

G.1. Transmission

In accordance with the NER TNSPs have the primary role in network planning although NEMMCO has a role in inter-regional planning. Network service providers must provide information to NEMMCO where network augmentations could impact across regional boundaries (clause 5.2.3(d)(12)).

G.1.1. Formal planning and reporting requirements

The NER require NEMMCO to prepare and publish an Annual National Transmission Statement (ANTS) setting out forecast constraints in respect of national transmission flow paths and alternative solutions (Rule 5.6.5). TNSPs undertake annual planning including a review of the adequacy of existing connection points and the transmission system and planning proposals for future connection points (Rule 5.6.2(b)). Where the annual planning review identifies the necessity for augmentation or non-network alternative, a TNSP must prepare joint plans with connected DNSPs that can be considered by participants, NEMMCO and interested parties

The relevant planning horizon is 10 years (Rule 5.6.2(d)).

Where the TNSP identifies emerging constraints on the basis of load forecasts it must notify NEMMCO and participants and of the expected time to allow the appropriate network augmentation, non-network alternatives or modification to connection facilities (Rule 5.6.2(e)).

The TNSP must prepare an Annual Planning Report setting out the results of the annual planning review (Rules 5.6.2A(a)-(b)) including:

- forecast DNSP loads;
- planned connection points;
- forecast constraints over 1, 3 and 5 years;
- proposed augmentations including reason (constraint or performance requirement), cost of proposed solution, and whether there is an inter-network impact;
- alternative network and non-network solutions including interconnectors, generation options, demand side options, market network service options and options involving other networks; and
- for proposed new small transmission network assets (augmentations with an estimated required capitalised expenditure of $1-10m), a ranking of alternatives according to the regulatory test, analysis of why the asset passes the regulatory test, reasoning if the asset

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88 End users or other parties who in NEMMCO’s opinion have, or who have identified themselves to NEMMCO as having, an interest in relation to network planning and development activities under clause 5.6, or who in the AER’s opinion have, or who have identified themselves to the AER as having, the potential to suffer material adverse market impact from a new large transmission network asset.
is considered to be a reliability augmentation, and an augmentation technical report if there is a likely material inter-network impact and other TNSPs have not consented.

Case-by-case assessment of projects that are large transmission network assets (augmentations with an estimated required capitalised expenditure greater than $10 million) which must be published as an ‘application notice’ and include (Rule 5.6.6):

- reason (constraint or performance requirement);
- alternative network and non-network solutions including interconnectors, generation options, demand side options, market network service options and options involving other networks;
- ranking of alternatives according to the principles of the regulatory test. The regulatory test requires a request for information as to the identity and detail of alternative options to the network asset (Rule 5.6.5A(c)(4));
- analysis of why the asset passes the regulatory test and reasoning if the asset is considered to be a reliability augmentation; and
- an augmentation technical report if there is a likely material inter-network impact and other TNSPs have not consented.

G.1.2. Consideration of non-network alternatives

Consideration of non-network alternatives to large transmission network assets, included in application notice (see above).

Consideration of non-network alternatives to small transmission network assets, included in Annual Planning Report (see above).

G.1.3. Public notification and requests for proposals

A TNSP must request information on non-network alternatives to a large transmission network asset as part of the Regulatory Test (Rule 5.6.5A(c)(4)) and must advise participants and interested parties through publication of the ‘application notice’ (Rule 5.6.6).

A TNSP must consult with interested parties on any matter relating to small transmission network assets proposed in the Annual Planning Report, or proposed in a report prepared subsequently. Interested parties may make written submissions. The TNSP must republish those parts of the report that materially change as a result (Rule 5.6.6A), and the AER must take these changes into account in determining the TNSP revenue cap and whether the asset satisfies the regulatory test.

G.1.4. Evaluation of options - economic test

The Regulatory Test and guidelines must be promulgated by the AER in accordance with Rule 5.6.5A. The test includes a cost-benefit analysis of the future based on scenarios with or without the new network investment and compared to the likely alternative option(s). These may include generation, demand side management, other network options, or the substitution of alternative forms of energy. The level of analysis required by the regulatory test should not be disproportionate with the scale and size of the new network investment being considered.
The regulatory test makes specific requirements if the network option would be a large transmission asset (Rule 5.6.5A(c)(4)).

G.1.5. **Regulatory oversight, compliance or dispute resolution**

Interested parties may make written submissions on application notices (i.e. relating to large transmission network assets) and request a meeting with the TNSP. The TNSP must publish a report summarising all submissions.

Parties may dispute the contents of the TNSP report on a large distribution network asset. The matters are limited (Rule 5.6.6(j)) to:

1. possible alternatives and their ranking according to the principles of the regulatory test;
2. whether there is a material inter-network asset;
3. whether the asset satisfies the regulatory test, and the basis for that assessment, but only if the asset is not a reliability augmentation; and
4. whether the asset satisfies the criteria for a reliability augmentation.

The AER is required to make a determination to resolve the dispute (Rule 5.6.6(l)), but its powers to do so are limited to the matters that may be disputed under Rule 5.6.6(j).

The AEMC has last resort planning powers and may direct participants to apply regulatory test to a potential transmission project (Rule 5.6.4).

G.2. **Distribution**

G.2.1. **Formal planning and reporting requirements**

A requirement for annual planning exists under the joint requirement with TNSPs to review the adequacy of existing connection points and plan proposals for future connection points (Rule 5.6.2(b)). Where the annual planning review identifies the necessity for augmentation or a non-network alternative, a TNSP must prepare joint plans with connected DNSPs that can be considered by participants, NEMMCO and interested parties (Rule 5.6.2(c)).

The planning horizon for a DNSP is five years (Rule 5.6.2(d)).

Where the DNSP identifies emerging constraints on the basis of load forecasts it must notify NEMMCO and participants and of the expected time to allow the appropriate network augmentation, non-network alternatives or modification to connection facilities (Rule 5.6.2(e)).

G.2.2. **Consideration of non-network alternatives**

Large distribution network assets (augmentations with an estimated required capitalised expenditure in excess of $10 million): the DNSP must include non-network alternatives in its consultation arising from the identification of emerging constraints (Rule 5.6.2(f)) and subsequently in its assessment of possible options to address emerging constraints (Rule 5.6.2(g)).
Small distribution network assets (augmentations with an estimated required investment between $1 million and $10 million): it is not clear whether the DNSP must include non-network alternatives in its assessment of possible options to address emerging constraints (Rule 5.6.2(g)).

**G.2.3. Public notification/Requests for proposals**

The DNSP must consult with affected participants, NEMMCO and interested parties on possible options, including DSR, generation options and market network service options. The DNSP does not need to consult if the network option would be a new small distribution network (Rule 5.6.2(f)).

**G.2.4. Evaluation of options - economic test**

For large distribution network assets the DNSP ‘must carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the regulatory test’ (Rule 5.6.2(g)). The outcomes of this assessment are to be made available to all relevant stakeholders (Rule 5.6.2(h)) and include its recommended option.

For small distribution network assets the DNSP ‘must carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the regulatory test’ (Rule 5.6.2(g)). It would appear the DNSP must still prepare a report demonstrating the outcome of this (Rule 5.6.2(h)).

**G.2.5. Regulatory oversight, compliance or dispute resolution**

Registered participants may dispute the DNSP recommendation if it is a large distribution network asset or has likely material impact on DUOS service charges (Rule 5.6.2(i)). DNSP and affected participants are required to negotiate to resolve the dispute or otherwise to do so through the dispute resolution process in Rule 8.2.
Appendix H. Examples of network planning provisions

Set out below are a number of examples showing how the various planning arrangements work in practice in different states. What this sample demonstrates is that despite some relatively similar requirements in the different states, particularly in terms of the annual planning arrangements, the nature of the plans presented vary significantly in terms of how it is presented and the level of detail included.

H.1. Annual planning process

Most of the states, including South Australia, New South Wales, Queensland, Victoria and Tasmania require DNSPs to produce an annual planning report. These are published in all states except Tasmania.

Given the similar planning requirements between the states most of the reports published under the various regimes present similar information, although the precise format differs even within states. Most planning reports recognise the role that the planning exercise plays in facilitating demand management solutions and a number explicitly call for expressions of interest.

H.1.1. New South Wales

Energy Australia publishes its Annual Electricity System Development Review (AESDR) as an appendix to its Capital Works Programme. The AESDR contains a list of tables with data on forecast demand and capacity for all of Energy Australia substations, as well as a simple ‘yes’ or ‘no’ answer to the question of whether an investment will be triggered in the next 5 years. Where a forecast demand exceeds capacity the table forecasts the number of hours and days that demand will exceed secure capacity. This approach keeps the AESDR as simply a book of emerging constraints, which needs to be read in conjunction with the Capital Works Plan to assess the likelihood of feasible demand management solutions.

Most other companies publish their annual plans as stand-alone documents that include varying degrees of detail about proposals identified for relieving the constraint.

Integral Energy includes a summary table, which simply identifies each substation, lists its total capacity and makes a comparison between this and the summer/winter forecast peak load in five years time. Emerging constraints are highlighted in red and accompanied by a short description of any constraint relief projects identified. For each constrained substation a further section gives a more detailed description. This includes a graphical representation of the load profile, characteristics of the load, network options and brief description of what requirements any non-network proposal would have to satisfy.

H.1.2. South Australia

Similarly ETSA Utilities includes forecasts for all substations on its network and provides a simple ‘yes’ ‘no’ to the question of whether the substation or feeder faces a forecast constraint in next three years. For those where a constraint is identified it provides more detailed information on the extent, frequency and duration of the expected overload. It also provides a graph indicating when forecast load is expected to exceed the n-1 planning standard for the substation and the feeder. The nature and characteristics of the load is briefly
described, i.e. if it is predominantly commercial or residential, and the load curve graphed. It lists the approved network solution and in some cases the indicative cost and when it would need too be introduced by. ETSA Utilities also flag in a number of cases where it considers demand management solutions might be viable.

**H.1.3. Victoria**

The distributor planning reports released by Victorian DNSPs follow a similar format. They all highlight where the projected load exceeds the planning criteria in the next 5 years and the preferred network option to manage the constraint. However, the way this data is presented varies. For example CitiPower and United Energy both include a discussion on each constrained substation, flagging when the constraint is expected to arise and what feasible options exist to resolve those constraints. SPAusnet on the other hand provides the same data but in a denser table format which requires a much more involvement from the reader highlighting where constraints occur and the extent of that constraint.

**H.1.4. Queensland**

The reports produced by Ergon and Energex in Queensland vary somewhat. Although both provide a list of priority network proposals, including an indicative cost and a completion date, only Ergon includes a detailed table that flags where demand is likely to exceed capacity at the individual substation. Unlike in a number of other reports this does not go into any further detail about specific constraints other than a very short comment on a potential network solution.

Although the data presented is roughly consistent across the reports the level of detail and accessibility vary significantly. An example of a simple step suggested by a DM proponent to improve accessibility would be to overlay the identified constraints onto a map of the network, possibly colour coded to identify the severity of the constraint.

**H.2. Request for proposals and evaluation**

The only states where the planning process extends beyond the publication of an annual plan is South Australia and New South Wales. In both of these states where specific constraints are identified, the DNSP is required to issue a request for proposals and evaluate the options it receives on an equal footing with a network solution. This additional step requires a more proactive approach from the DNSP than in other states.

The DNSPs in both New South Wales and South Australia have been developing their demand management capacity in order to meet these requirements, for example ETSA Utilities has established a specific demand management unit within the business. ETSA Utilities reports in its 2006 demand management compliance report that in the previous year 14 projects passed its reasonableness test for which it had issued RFPs.

**H.2.1. New South Wales – Energy Australia**

Arguably the distributors in New South Wales have the most developed procedures for considering alternative non-network solutions, which given the requirement of a screening process (which South Australia is also now proposing to introduce) involves a significant evaluation of the options before going out to consultation. The flow chart below illustrates
the process that Energy Australia has developed for assessing network and non-network solutions as part of its process.\footnote{See Energy Australia website: Energy Australia Demand Management Process. Viewed 3/05/07}

(a) Energy Australia Demand Management Overview

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{demand_management_diagram.png}
\caption{Diagram of Energy Australia Demand Management Process.}
\label{fig:demand_management}
\end{figure}

Source: Energy Australia website. Viewed 3/05/07

H.2.1.1. Statement of need and network option

Where forecasts indicate an emerging constraint on the network Energy Australia develops a statement of needs, a baseline option against which any network or non-network solutions can be compared.

H.2.1.2. Demand Management screening process

The screening test is designed to identify the drivers behind the emerging constraint, the nature of the demand that is driving load growth and the potential of demand management as an option to alleviate it. It is then decided whether it is reasonable to expect DM to be a cost effective option to defer or avoid a supply side investment and whether further investigations should be conducted. This is done as early in the project as possible to allow sufficient time for investigation and development of an identified option and the outcome of the screening test published. Energy Australia describes the screening test as a tool to ensure resources are prioritised and allocated to those areas that have most potential to deliver cost effective DM solutions.
H.2.1.3. DM investigation

The detailed investigation is designed to determine if there are cost effective DM options that could defer network investment, and to identify the size, timing and costs of these feasible options. Based on the screening test the investigations expands the options identified, considers the amount of load reduction available and the net cost to Energy Australia. These options are identified through public consultation, existing knowledge, field visits and discussions with specific customers.

H.2.1.4. Consultation – request for proposals

Energy Australia describes its consultation process as an opportunity to identify potential options that are known to third parties but that it might not be aware of. The RFP is publicly advertised and sent to interested third parties. EA continues to investigate options in parallel with this process, conducting site visits and contacting major customers itself.

The consultations document sets out first the details of the current supply conditions including a map of the area. It provides information relating to the forecast peak demand and charts details of forecast load versus supply capacity limits. It further provides very high-level indication of the type of customer (i.e. commercial or residential), the profile of the peak load and identifies how much load reduction would be required and by what date. The report provides a graphical representation of the value of demand reductions showing how much demand reduction would be required at what cost.

H.2.1.5. Evaluation - DM investigation report

All options identified either by Energy Australia or third parties through the request for proposals are analysed according to size (MVA), cost (both NPV and $/KVA), time of day seasonality, and reliability/risk. Costs of the DM alternatives are compared to the value of deferring the network expansion option to establish the packages of DM options that can potentially be cost effective in deferring the proposed augmentation.

The DM Investigation Report describes the investigation process followed, identifies all DM options considered, lists the cost and impacts ascribed to each and describes any feasible DM options that are to be considered alongside network augmentation options.

H.2.1.6. Evaluation report – Drummoyne

Although a relatively small number of DM investigations appear to be reaching a successful conclusion, a good example of this dual investigative and consultative process that Energy Australia use can be found in its response to an identified constraint at Drummoyne in Sydney. In this case it had 9 responses to its request for proposals, including 6 firm proposals. In the end it analysed 8 demand management options:

- contracting with customers who have standby diesel generators and using the generators to provide short period demand reduction when required;
- installation of power factor correction equipment at customers premises;
- instillation of fixed dimming systems to commercial lighting;
upgrading of commercial lighting system using retrofitted efficient lighting kits;
peak load control by advanced control systems;
peak demand reduction by using advanced residential metering and control devices;
residential compact fluorescent lamp (CFL) direct distribution program; and
installation of thermal storage systems.

Energy Australia identified that the power factor correction and a direct delivery CFL program in residences could provide about 1MVA winter peak demand reduction in the Drummoyne area. Based on the size, cost and reliability profile of this option, it concluded that it could provide a cost-effective means of deferring the proposed supply side investment by one year and should be considered for further development.\(^9\)

**H.2.2. ETSA Utilities – RFP and evaluation report**

Under Guideline 12 in South Australia, ETSA Utilities is required to follow a similar process for identified constraints, issuing an RFP for those that pass a reasonableness test, and evaluating the options received.

The RFP provides a detailed description of the supply conditions at the point of the constraint, including details of the current conditions, the forecast load in the region and the expected capacity constraint. The RFP also sets out the criteria for evaluating proposals, identifying a number of conditions that must be met for the proposal to be accepted:

- the size of the load reduction must be large enough to meet the annual increase in demand;
- options must be capable of meeting load growth during peak months;
- must reduce electricity demand in the identified area;
- must be available within an appropriate timeframe;
- must meet reliability standards;
- options must provide certainty, be committed using proven technology and have funding and project management to deliver within the required timeframe; and
- options must be capable of providing solutions to the proposed limitations for a period of at least 10 years. Alternatively solutions must be able to defer additional network investment for a number of years.

ETSA Utilities notes the evaluation period is driven by the need to obtain the most cost effective development over a reasonable time frame, allowing for uncertainties associated with expected network development and load generation patterns. Most of the RFP issued are a result of load growth. ETSA Utilities stresses in these cases there is considerable uncertainty associated with forecasting future supply arrangements, in which cases it tends to use a ten year evaluation period.

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\(^9\) Demand Management Investigation Report, Drummoyne, 1 February 2006
Although it has issued a number of RFPs and at various points discussed possible DM options with several proponents, we understand it has yet to develop a proposal fully.

The evaluation report considering the upgrade of the Port Noarlunga substation identifies some of the difficulties that these type of solutions face. In this example a proposal was received to install capacitors in the area, this could have potentially have deferred augmentation by one year. While the solution was primarily rejected because it was deemed more expensive than a network solution, ETSA Utilities highlighted a number of other barriers that could have prevented its application. Firstly, ETSA Utilities did not consider the time frame sufficient to undertake the required degree of testing before it would allow this new equipment be installed on its network. In addition ETSA Utilities considered that the proposal did not fully assess the potential costs that would be involved in introducing this, in particular that it did not consider costs relating to:

- customer education and acceptance of the programme;
- domestic customer penetration needs to 100% to achieve the solution;
- liability insurance to achieve guaranteed availability for customer installations;
- engineering and system proving for customer installation;
- design and implement maintenance and safety procedures;
- OH&S safety compliance; and
- ETSA Utilities administration and implementation costs.

This demonstrates some of the difficulties around developing a proposal compliant with the DNSPs requirements, particularly providing the requisite degree of certainty that the DNSP seeks and identifying costs that largely sit within the DNSP.
## Appendix I. Summary of recommendations

<table>
<thead>
<tr>
<th>Issue</th>
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<th>Recommendations</th>
<th>Relevant Rule in NER or jurisdictional regime</th>
<th>Materiality of issue</th>
</tr>
</thead>
</table>
| Network development and planning arrangements | 1   | The Rules should require DNSPs to undertake an annual planning process and publish an annual planning report that sets out the outcomes of that planning process. The annual planning report should include:  
  1) a 5-year forecast of potential constraints, together with preliminary estimates of the costs of network solutions;  
  2) a forecast of areas of substantially under-utilised existing transfer capability;  
  3) a forecast of average and marginal distribution loss factors for different points in the network over the planning horizon; and  
  4) a description of the DNSP’s compliance with their planning-related obligations, including:  
  a) a summary of case-by-case applications of the regulatory test completed in the previous year, and on the status of the relevant projects (and the status of any projects from previous years); and  
  b) the results of applying the regulatory test to projects below the threshold for a case-by-case process but that meet the threshold for transparent reporting and the status of the relevant projects (and the status of any projects from previous years).  

The annual planning reports (and any other planning-related information) should be made public and available from a single point (such as the NEMMCO website). | Proposed for 5.6.2 | High |
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<tr>
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</table>
| Network development and planning arrangements (cont.)      | 2   | The AER should be required to produce a statement of specific requirements that is given effect by the Rules that sets out the standard format and required contents of the annual planning report. The Rules should set out the matters the AER’s statement of specific requirements is permitted to address, which should include:  
  - requiring an accessible summary of where and when constraints are expected to emerge over the planning horizon and of the value of deferring the associated network augmentations (e.g. in S$/kVA per annum terms);  
  - requiring an accessible summary of the extent of surplus capacity at different points in the network;  
  - requiring an accessible summary of the magnitude of current and forecast average and marginal distribution loss factors at different points in the network; and  
  - requiring a standard format for reporting on applications of the regulatory test. | Proposed for 5.6.2 | High                 |
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<tr>
<td>Network development and planning arrangements (cont.)</td>
<td>3</td>
<td>For any project to alleviate a network constraint for which the network solution would require an estimated capitalised expenditure of $2m or more, DNSPs should be required to perform an economic cost-benefit assessment of that project (see recommendation 6). As part of this assessment, the DNSP should be required to consult publicly and be required to issue an RFP from potential providers of non-network solutions to the network constraint. The DNSP should be required to report publicly the results of its assessment immediately after its assessment has been completed, and also to summarise the outcomes of the assessment in its annual planning report (see Recommendation 1).</td>
<td>Proposed for 5.6.2(f)</td>
<td>Moderate to High</td>
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<td>4</td>
<td>For any network constraints for which the network solution would require an estimated capitalised expenditure of $0.5-2m, DNSPs should be required to undertake an economic cost-benefit assessment of the project and publish the results in the annual planning report, without being required to issue an RFP or consult on the options. We observe that for network constraints for which the network solution would require an estimated capitalised expenditure of less than $0.5m, there would be no formal ex post reporting requirement: DNSPs would not be required to undertake an economic cost-benefit assessment of the project, to issue an RFP or to consult on the options. The ex ante requirement to identify emerging constraints in the annual planning report would, however, apply to projects of this magnitude.</td>
<td>Proposed for 5.6.2(f)</td>
<td>Low</td>
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<td>Network development and planning arrangements (cont.)</td>
<td>5</td>
<td>The Rules should require the AER to issue a statement of specific requirements that sets out the contents of a Request for Proposals for non-network solutions to address an emerging network constraint and that sets out the process to be followed in issuing such requests.</td>
<td>AER statement of specific requirements and 5.6.2(f) of the rules</td>
<td>High</td>
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</table>

The Rules should require the AER statement to require the RFP to include, at a minimum:

- the technical requirements that the non-network solution would need to meet;

- the estimated range of costs for network solutions and an indication of the resulting annual cost that a non-network solution would need to better in order to be selected; and

- an indication of whether the DNSP considers non-network alternatives to be a feasible solution for the project.

The Rules should require the AER statement to require the RFP process at a minimum to:

- provide sufficient time for proponents of non-network solutions to prepare their cases while allowing the DNSP, in the absence of a committed non-network project, to implement a network solution after a cut-off date; and

- ensure that the RFP process is be capable of being brought to closure, with the non-network solution either committed (and bound) to deliver in a reasonable period of time, or the DNSP free to select an alternative option.

The Rules should require all RFPs to be published in the same central location as the annual planning reports.
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<tr>
<td>Network development and planning arrangements (cont.)</td>
<td>6</td>
<td>DNSPs should be required to apply the standard regulatory test (rule 5.6.5A) when undertaking a cost-benefit assessment of alternative projects (requiring amendment to clause 5.6.2(g)) so long as it continues to provide the flexibility for the test to be applied in a manner that is proportionate to the size and scale of the project.</td>
<td>Proposed for 5.6.2(g)</td>
<td>High</td>
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<td>7</td>
<td>The DNSP’s obligations to undertake the annual planning and reporting activities, and to undertake project evaluations, should be Rules obligations and able to be enforced through standard Rules-enforcement processes.</td>
<td>Any change would affect 5.6.2(i)</td>
<td>Moderate</td>
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<td>8</td>
<td>A dispute resolution regime based on rules 5.6.6(j)-(n) should exist in relation to the DNSP’s conduct of a cost-benefit assessment (and associated RFP for non-network options) for particular distribution projects, which should have the following features:</td>
<td>Proposed for 5.6.2(i)</td>
<td>Moderate</td>
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<td>‡ <strong>threshold</strong> – should be limited to projects that are new large distribution assets (currently projects whose total capitalised cost is $10m and above);</td>
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<td>‡ <strong>parties to the dispute</strong> – extend to parties directly affected, which would include proponents of non-network options, end-users and agents on their behalf;</td>
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<td>‡ <strong>scope of the dispute</strong> – should not be significantly limited;</td>
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<td>‡ <strong>dispute resolution process</strong> – the AER should have the role of hearing the dispute and adopt a low cost process for this; and</td>
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<td>‡ <strong>effect of the dispute</strong> – the current effect of the mechanism, whereby the DNSP cannot be directed in its activities, should be maintained.</td>
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<tr>
<td>Network development and planning arrangements (cont.)</td>
<td>9</td>
<td>The Rules should ensure that DSR/DG trials and risk sharing arrangements are encouraged in order to build trust and communication between DNSPs and proponents of non-network alternatives. In addition, the regulatory framework should be reviewed to determine whether insufficient incentives are provided to DNSPs to invest efficiently in research and development, warranting the development of a specific incentive mechanism in the Rules.</td>
<td></td>
<td>Moderate</td>
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</table>
| Network connection arrangements | 10 | Specify in the Rules the connection requirements that must be met by a user which include the requirement for users to:  
- pay the DNSP for the construction of any dedicated connection assets (where the construction of these assets is not contestable) and any extension works to the distribution system required to effect the connection; and  
- comply with technical and safety requirements in relation to the customer’s installation or equipment, ie, payment for extension assets, dedicated connection assets and compliance with technical and safety matters. | Proposed for Rule 5.3 | Moderate |
<p>| | 11 | Schedules to Chapter 5 of the NER should be amended to include a definition of the technical requirements for small load, large load, micro, small and medium DGs. | Proposed for schedules to Chapter 5 | Moderate to high |
| | 12 | The NER should define the standard connection services to apply to micro DGs. | Proposed for Rule 5.3 | Moderate to high |</p>
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<td>13</td>
<td>The NER should set out the minimum content for standard applications in a schedule to Chapter 5.</td>
<td>Proposed for schedules to Chapter 5</td>
<td>Moderate</td>
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</table>
|       | 14  | The NER should:  
- set out the minimum content for standard connection contracts in a schedule to Chapter 5 including a requirement for the DNSP to specify the number of days after the finalisation of the agreement that the standard connection will be effected;  
- require the AER to approve the content of the standard application form and the terms and conditions specified in the standard contract and require the AER to apply the ‘fair and reasonable’ test when determining whether to approve the proposed standard contracts. | Proposed for Chapter 5 and schedules to Chapter 5 | Moderate to high |
|       | 15  | The NER should state that the negotiation framework developed in accordance with Draft Rule 6.7.5 and as modified should apply in the negotiated connection application process.  
Rule 6.7.5(c) should be modified to include the following additional provisions which would require the DNSP to specify:  
- a requirement for the exchange of technical as well as commercial information between the two parties;  
- a requirement that when considering a connection application the DNSP is to use its reasonable endeavours to provide the user with the service it requires in accordance with the reasonable requirements of the user, including without limitation, the location of the proposed connection point and the level and standard of power transfer capability that the network | Proposed revision to Draft Rule 6.7.5 | Moderate |
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<td>will provide (currently Rule 5.3.6(d));</td>
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| Network connection arrangements (cont.)    | 15 (cont.) | β any offer pertaining to a negotiated distribution service to be fair and reasonable and consistent with the safe and reliable operation of the power system in accordance with the NER and consistent with the technical requirement schedules contained in Chapter 5 (as applicable) and must not impose conditions on the user that are more onerous than those contemplated in these technical schedules (currently Rule 5.3.6(c));

β the cooling off period that will apply to any contract negotiated with vulnerable users;

β a requirement that when considering a connection application the DNSP must consult with any affected Distribution Network Users and NEMMCO (where relevant) if the DNSP believes, in its reasonable opinion, that compliance with the terms and conditions of those connection agreements will be affected, in order to assess the application to connect and determine:

– the technical requirements for the equipment to be connected;

– the extent and cost of augmentations and changes to all affected networks;

– any consequent change in network service charges; and

– any possible material effect of this new connection on the network power transfer capability including that of other networks (currently Rule 5.3.5(d)); and

– the time periods for the commencement and finalisation of negotiations relating to negotiated connections once a completed application form is submitted to the DNSP for the alternative types of users and connection requirements. | Proposed revision to Draft Rule 6.7.5 | Moderate |
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<td>Network connection arrangements (cont.)</td>
<td>16</td>
<td>Schedule 5.6 of the NER should be amended: [] to ensure that it can be utilised in contracts negotiated with small users, large users, micro, small and medium DGs; [] to include a cooling off period for those contracts negotiated with small users; and [] to include provisions which enable the connection agreement to be modified over time where both parties agree to changes in non-price terms and conditions (including technical conditions which may require NEMMCO involvement) and where those changes have no associated cost effects.</td>
<td>Schedule 5.6</td>
<td>Moderate</td>
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<td>Network connection arrangements (cont.)</td>
<td>17</td>
<td>The NER should require a DNSP, within five business days of receiving a user’s initial enquiry: § to advise the user whether there is a standard connection service that would encompass its connection requirements and if so: – supply the user with the relevant standard contract and application form; and – inform the user that they have the option of using either the standard connection service or negotiating an alternative connection service. § to provide the user with a copy of the negotiation framework it has developed in accordance with Rule 6.7.5 and that has been approved by the AER which will come into operation if the connection service is to be negotiated; § to inform the user of whether any aspects of the connection service are contestable; § to inform the user of any additional information required which is of the kind specified in Schedules 5.4; and § to inform the user of the indicative value of the loss factor applying in the area within which the user is seeking connection.</td>
<td>Proposed revision to Rule 5.3</td>
<td>Moderate</td>
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<td>18</td>
<td>The NER should require a user in the connection enquiry phase to advise the DNSP whether it will be seeking connection via the standard connection service route or the negotiated connection service route.</td>
<td>Proposed revision to Rule 5.3</td>
<td>Moderate</td>
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| Network connection arrangements (cont.) | 19  | The NER should state that where a user selects the standard connection application route the DNSP must:  
- advise the user as soon as practicable, and no later than five business days after receiving advice from the user that it will be seeking the standard connection service route, if the application should be processed by another DNSP; and  
- within five business days provide the user with any technical information necessary to process the application in accordance with the technical schedules in Chapter 5 to the extent that it holds such information. | Proposed revision to Rule 5.3 | Low |
| 20   |     | The NER should require the DNSP to issue a connection offer and a standard connection agreement within twenty business days of receiving a completed standard application form. | Proposed revision to Rule 5.3 | Moderate |
| 21   |     | The NER should allow a user (utilising the standard connection application route) two months to accept the offer otherwise the offer should be deemed to have lapsed unless the DNSP agrees to extend the offer. | Proposed revision to Rule 5.3 | Low |
| 22   |     | The NER should state that where an application is for a negotiated connection service the DNSP must within ten days:  
- advise the user if the application should be processed by another DNSP; and  
- provide the user with any technical information necessary to process the application in accordance with the technical schedules in Chapter 5 to the extent that it holds such information. | Proposed revision to Rule 5.3 | Low |
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| Network connection arrangements (cont.) | 23  | The NER should:  
β combine the technical, price and non-price negotiation phases currently set out in the application for connection and offer to connect phases;  
β remove any provisions which will be captured in the negotiation framework specified in Rule 6.7.5;  
β require the DNSP to commence negotiations with the user as soon as it submits a completed application form; and  
β require both the DNSP and user to negotiate in good faith  
β state that any negotiation relating to access standards must:  
- be no less onerous than the minimum access standard contained in the relevant schedules in Chapter 5;  
- not adversely affect power system security;  
- not adversely affect the quality of supply for other users; and  
- involve NEMMCO in an advisory capacity and accord NEMMCO twenty business days to inform the parties in writing of any advisory matters arising as a result of the proposed negotiated access standard.  
β require the DNSP to develop an offer to connect which contains the information specified in Schedule 5.6 and specifies the outcome of any negotiation relating to access standards, connection charges, prudential requirements and any other terms and conditions within the time specified in the preliminary program or later if the access standards have been negotiated. | Proposed revision to Rule 5.3 | Moderate |
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<tr>
<td><strong>Network connection arrangements</strong></td>
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<td>(cont.)</td>
<td>24</td>
<td>The NER should allow the user (utilising the negotiated connection application route) two months to accept the offer otherwise the offer should be deemed to have lapsed unless the DNSP agrees to extend the offer. The NER should allow, subject to a decision by the AER as to the form of regulation to apply to the provision of connection assets, a DNSP to recover from connecting users the cost of dedicated connection assets as well as extension assets for the sole use of a new connection that, but for the new connection, would not have been incurred – a connection asset charge.</td>
<td>Proposed revision to Rule 5.3</td>
<td>Low</td>
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<tr>
<td><strong>Capital contribution requirements</strong></td>
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<td>25</td>
<td>The NER should allow, subject to a decision by the AER as to the form of regulation to apply to the provision of connection assets, a DNSP to recover from connecting users the cost of dedicated connection assets as well as extension assets for the sole use of a new connection that, but for the new connection, would not have been incurred – a connection asset charge.</td>
<td>Proposed revision to Chapter 5 or Chapter 6</td>
<td>Moderate to High</td>
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<td>26</td>
<td>The NER should adopt the terminology in Box 4.1 for the purposes of calculating a connection asset charge.</td>
<td>Proposed revision to Chapter 5 or Chapter 6</td>
<td>Moderate</td>
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<td>27</td>
<td>A compulsory connection asset charge should not include the cost of any shared network augmentation that may be required to service the load/generation output arising from a new connection. However, a connection applicant may also choose to fund shared network augmentation by negotiation between the DNSP and the connection applicant.</td>
<td>Proposed revision to Chapter 5 or Chapter 6</td>
<td>Moderate to High</td>
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</table>
|                                     | 28  | The NER should require the AER to develop a Guideline for the determination of connection asset charges. The Rules should provide that the Guideline include:  
- a definition of a standard small customer connection asset that may vary for each DNSP, for which no connection asset charge may be levied; and  
- a definition of the relevant connection point. | Proposed revision to Chapter 5 or Chapter 6   | Moderate              |
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| Capital contribution requirements (cont.) | 29 | The NER should require the AER to develop a Guideline that provides a methodology for the partial repayment of connection asset charges when a new customer connects to an extension asset within 7 years. The Rules should provide that the Guideline include:  
- an obligation for a DNSP to provide a repayment to a connection customer in the event a new connection utilises part of the previously dedicated assets;  
- dispute resolution procedures;  
- the basis for calculating the repayment; and  
- a requirement that the asset become treated as a shared network asset at the expiry of the seven year period. | Proposed revision to Chapter 5 or Chapter 6 | Moderate |
<p>| | 30 | Provisions within the NER that currently refer to the recovery of network augmentation costs through a connection charge should be removed (ie, Rule 5.5(f)(3)(i) and Draft Rule 6.22(1)(b). | Rule 5.5(f)(3)(i) and Draft Rule 6.22(1)(b) | Moderate to High |
| Network loss factors | 31 | It is proposed that DG receive a DLF that reflects the amount of losses that the DG would avoid by being present and operating (i.e. a marginal loss factor). In contrast, customers would continue to receive a loss factor that distributes the losses to be recovered across customers in proportion to each customer’s usage, where the losses to be recovered are the sum of the forecast of actual losses and the sum of the ‘avoided losses’ from DGs. | Rule 3.6.3 in general will need to be revised to distinguish between DG distribution connection points receiving a site specific marginal loss factor, those receiving a geographically averaged marginal loss factor and customer distribution connection points. In particular, those rules that require average losses to be used will need revision: Rules 3.6.3(b)(1), 3.6.3(b)(2)(ii) and 3.6.3(h) | High |</p>
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<tr>
<td>Network loss factors (cont.)</td>
<td>32</td>
<td>Marginal loss factors for site specific DG would be calculated on the basis of the forecast losses with the DG being present and operating as forecast, compared to the losses that would be forecast in the absence of that DG. For smaller sites, the distribution loss factor should reflect a marginal loss factor (averaged across the relevant geographic area), but estimated in a manner that keeps the computation burden to a reasonable level – for example, through the use of a ‘rule of thumb’ relationship between average and marginal loss factors.</td>
<td>As above: Rule 3.6.3 in general, and in particular Rules 3.6.3(b)(1), 3.6.3(b)(2)(ii) and 3.6.3(h)</td>
<td>High</td>
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<td>33</td>
<td>The AER should be encouraged to require the price that a DNSP charges to determine a site specific DLF for a DG or customer that is below the threshold in the Rules be a regulated service (for example, by requiring it to be listed as an alternative control service).</td>
<td>Any measures to be reflected in the rules would affect Rule 3.6.3(b1)</td>
<td>Moderate</td>
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<td></td>
<td>34</td>
<td>DNSPs should be required to calculate a separate loss factor for geographic regions that are expected to suffer materially different levels of losses, and to combine geographic regions for this purpose only where they are expected to suffer materially similar levels of losses.</td>
<td>Rules 3.6.3(c)-(h)</td>
<td>Moderate-High</td>
</tr>
<tr>
<td></td>
<td>35</td>
<td>A site should be treated for DLF purposes as a ‘customer’ when it imports, and a ‘generator’ when it exports, on the gross flows of electricity, requiring two metered connection points at a site that is a combined distributed generator and customer.</td>
<td>Rule 3.6.3</td>
<td>High</td>
</tr>
<tr>
<td>Issue</td>
<td>No.</td>
<td>Recommendations</td>
<td>Relevant Rule in NER or jurisdictional regime</td>
<td>Materiality of issue</td>
</tr>
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<tr>
<td>Network loss factors (cont.)</td>
<td>36</td>
<td>Allow, but not require, the AER to develop an incentive mechanism for DLF management guided by the principles of:</td>
<td>Proposed clause 6.6.2 in the draft Distribution Rule appears sufficiently generic to accommodate a loss incentive scheme.</td>
<td>Moderate</td>
</tr>
<tr>
<td></td>
<td></td>
<td>§ the need to ensure DNSPs’ motivations for controlling and forecasting losses are aligned with the potential costs / benefits of changed losses or better forecasts;</td>
<td></td>
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<td>§ the need for neutrality in deciding between network and non-network options; and</td>
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<td>§ control of losses – rather than accuracy of forecasts – is likely to be of more significance to efficiency.</td>
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</tbody>
</table>