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Manager, MCE Secretariat,
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Dear Sir / Madam,

Network Planning and Connection Arrangements

EnergyAustralia welcomes the opportunity to respond to the Independent Report on distribution network planning and connection arrangements. While we understand that this paper has not been considered by the SCO, we are concerned that the recommendations provided in the paper limit the scope of future policy analysis on what are significant energy reform issues.

We note our concerns with the paper below:

- **Rather than focussing on a broad range of issues for developing a National framework for network planning, the paper concentrates on the consideration of non-network solutions.**

  EnergyAustralia believes that designing a national framework for distribution network planning requires careful consideration of a broad range of issues. In New South Wales, a considerable amount of information regarding network planning and investment is made public on an annual basis. There has been little analysis of the extent to which the information provided is useful to stakeholders. Nor has there been a proper analysis of economic evaluation on a case by case basis in a distribution context.

  We would have expected a report such as this to scope a broad spectrum of issues in relation to network planning. Instead the recommendations seem to focus on addressing two main issues:

  1. "..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" (p3);
  2. "...DNSPs have insufficient incentive to ... consider non-network solutions when planning network augmentations" (p3).

While these perceptions are an important consideration in the context of the broader framework for network planning and reporting, they are best dealt with as part of the incentive framework for economic regulation. The recommendations for administrative arrangements are therefore clouded by a disproportional focus on financial incentives for efficient investment and non-network solutions.

- **There are important outstanding issues from the economic or non-economic energy reform packages that were not addressed in the paper.**

  EnergyAustralia has raised significant concerns with the economic framework which:

  1. gives considerable power to the AER to classify existing services;
  2. bases the classification (form of regulation) criteria on the basis of economic factors without due reference to issues of access;
  3. places an arbitrary distinction in service classification between services that are subject to negotiation and services that are not; and
  4. deferred consideration of how to deal with connection services which begin their life cycle as a contestable service and are then "contributed" to the DNSP to operate with other assets as part of its "use of system" service.

  Similarly, we raised concerns with the Retail Policy Working Group on many aspects of the proposed regulatory framework for contractual and service obligations including where the obligations on the DNSP commence (upon connection application or upon energisation) as well as the extent to which these obligations are reflected in the contractual obligations.

  We would have expected many of our concerns to be addressed in this paper. However, the paper only adds to the existing confusion of how connection services will be regulated in the future.

  - There seems to be little recognition that many connections are paid for by the customer independent of the DNSP;
  - The paper alludes to the fact that connection arrangements will be classified as a negotiated service which would represent a fundamental shift in the existing framework;
  - There is uncertainty as to what class of customers the framework in the paper applies to. While it seems to exempt small retail customers it also refers to treatment of "vulnerable customers".

  In short, there is considerable overlap within three workstreams undertaken by the MCE which either refer or defer to each other. As a result, fundamental aspects of regulatory design (such as service definition) are not being addressed on a holistic basis. The outcome is a confusing and disjointed reform process which does not address core issues.

- **The paper does not properly assess the costs of increased regulatory burden ultimately borne by customers against the benefits that customers will receive.**

  The recommendations in the paper, if endorsed will lead to significant increases to the DNSP in terms of regulatory compliance. Our concern is that these costs were not properly considered against:

- the problem that the additional compliance was intended to resolve; or
- the likely outcomes of the additional compliance and the intended benefits.

  Like any other regulatory obligation, the DNSP will resource itself to meet the costs of compliance which will ultimately be passed on to customers. Policy makers must therefore be mindful of the benefits that customers will receive in return for the additional costs. Nevertheless, we remain concerned that an increasingly onerous compliance regime will shift focus from looking proactively toward solutions to complying with regulatory obligations.

- **The paper lacks assessment of the practical application of many of the issues investigated.**

  We are concerned that the paper was limited to a desktop review of regulatory frameworks, rather than a full analysis of how those regulatory frameworks are applied in each jurisdiction. For example, the paper refers extensively to the Demand Management Code in New South Wales, but fails to appreciate that the Code has no force beyond a requirement that it be taken into account by DNSPs when preparing their network management plans, which are then implemented. In practice, EnergyAustralia uses a quite different process that achieves the principles of the Code in a way that ensures that focus is placed on those areas of the network where non-network solutions are feasible. Our processes and plans are made public on our website.

I understand that stakeholders across the industry, including proponents of non-network solutions and user groups were equally concerned with the recommendations in the paper and for similar reasons to those I have mentioned above. EnergyAustralia would therefore recommend that this paper be used as a starting point for a broader review of some of the intricacies of network planning and connections. We believe that these types of reviews are best dealt with following intensive industry consultation and lend themselves more to an independent assessment by the AEMC.

I have attached for your information:

1. A more detailed response to the specific recommendations outlined in the paper
2. Several case studies demonstrating our concerns with the recommendations in the paper.

I look forward to responding to a more detailed and wider consultative review in the coming months.

Yours sincerely

George Maltabarow

GEORGE MALTABAROW
Managing Director

Recommendations and Comments

	Recommendation	EnergyAustralia Comment

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:
	    o 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
	    o 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).
		The increase in regulatory requirements on the DNSP to undertake and publish a report with these requirements will involve costs that are not insignificant. Ultimately these costs are imposed on the market as a whole.
		
		EnergyAustralia questions whether the increased cost to customers of complying with the additional regulatory requirements has been adequately considered. This is particularly important as the report has not established the extent to which this approach will result in additional DSM or DG activity or whether the current lack of DSM and DG under the planning process is evidence of an inefficient planning and investment process in the first place.
		
		In general these requirements are impractical for distribution networks are characterised by a multitude of relatively short lead time projects.

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	There is enough flexibility in the Law now for the AER to require additional information. This recommendation potentially creates a disconnect between what the Rules require and what the AER wants. Note concerns of recommendation 1

	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.	By April each year, NEMMCO is required to publish next years DLFs under clause 3.6.3(i). A cursory review of losses will demonstrate substantial instability in losses, driven primarily by weather effects on loading. As such, forecasting network losses at particular points on the network, beyond the next year, is guesswork. For the EnergyAustralia network, the difference between an average DLF versus a marginal DLF is likely to be 5% vs 6.5%. Such a change is unlikely to have any impact on a DG's decision about their location to connect or the viability of their business case.
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).	These recommendations seem to be based more on observation of perceived practice in jurisdictions. However, the report incorrectly interprets existing practices in New South Wales. We submit that compliance with this recommendation would involve considerable regulatory cost, which is ultimately borne by customers. Again, EA is concerned that these costs will not be offset by benefits in more efficient network planning and investment. The proposed capital threshold of $2M is too low to contemplate for an RFP (as it amounts to a deferral benefit and consequent funding limit for economic DM in the order of only $200,000 per annum and would impose administration costs in the order of tens of thousands).
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.	There does not appear to have been any assessment of the cost of conducting an RFP process and whether the cost is justified by the perceived benefit. As regards the level at which an RFP process should be undertaken, it should be noted that the Demand Management Code of Practice is not mandatory in New South Wales. The Code is required to be

		taken into account when preparing Network Management Plans under the Electricity Supply (Network Safety and Management) Regulation. In any case, the threshold in the Code for the application of an RFP process is not $200,000 per project rather it is where the estimated forecast annualised cost of adequate system support is at least $200,000 for at least one year.
Recommendation 5	The Rules should require the AER to issue a statement of specific requirements that sets out the contents of a Request for Proposal 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	The AER should not be conferred with guideline making powers in relation to matters which are clearly appropriate for Rules. This will create a further regulatory process which is unnecessary and will inevitably result in regulatory creep due to the AER seeking to regulate beyond the matters contemplated in the rules. For example, it is not clear how guidelines are necessary to ensure that the RFP process is capable of being brought to closure within a reasonable time or whether it is necessary to be addressed by a guideline. It would be preferable for the Rules to clearly specify the requirements for the RFP process and for the Rule change process to be used if additional matters are necessary.

	(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.	
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.	The regulatory test was initiated well before these more codified obligations and incentives were established. Investment planning frameworks will need to demonstrate a robust assessment of options and a process for assessing least cost alternatives to meet reliability obligations as part of the regulatory determination process, otherwise the AER will not accept the assumed capital forecasts proposed. We suggest the regulatory test as it applies to distribution networks should be revisited in the context of the new regulatory regime, which has a very strong incentive for NSP's to ensure that capital expenditure is efficient. This could result in a substantial increase to the current threshold expenditure levels in the regulatory test.
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.	It is vital to remember that a vast majority of the projects are necessary to meet reliability standards and ensure essential supply to customers and the timing of such requirements should not be jeopardised through any administrative process. The current obligation whereby a DNSP has an obligation to arrange for the network options to be available for service by the agreed time (5.6.2(k)) should be revisited where augmentations are driven by the need to meet regulatory obligations. This obligation currently gives rise to confusion as there is no "agreed time" under the existing framework nor is it appropriate for there to be one. The obligation to meet reliability obligations imposes sufficient obligation and there should not be an artificial obligation imposed through the Rules.

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.	The purpose of a general right to raise a dispute in relation to recommended course of action is not apparent under the existing or proposed framework. The recommendation that the DNSP should not be directed in its activities is supported, however the other matters which can be the scope of dispute should be specified.
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, warranting the development of a specific incentive mechanism in the Rules.	EnergyAustralia agrees that this is where the focus should be in the short term. It must be recognised that network investments are relatively well understood, have known risks and performance, and provide a correspondingly low rate of return. On the other hand, many DSR/DG options have less well understood performance implications and risks and when evaluated against network options must be considered in that light in meeting network licence and performance obligations. It is therefore entirely appropriate that the risk associated with DSR/DG should be apportioned between the DNSP and proponent, and that the DNSP should be compensated for the additional financial risk and costs it would bear.

General comments on section 3. Section 3 of the paper is confusing on its intended scope. For example page 41 states that the report only relates to network connection arrangements for users other than "standard" small retail load customers, recommendations 15 and 16 refer to cooling off periods for "vulnerable customers". It was stated at the forum that these cooling off periods were only intended to apply to small load customers. Also the paper appears to assume that certain obligations imposed under the NSW Electricity Supply Act apply to embedded generators in the same way as they apply to load customers, this is not the case. For example the obligation to connect only applies to load customers and does not apply to embedded generators unless such generation was purely incidental to the customers connection for load. Also the IPART determination in relation to capital contributions does not apply to embedded generators, see para 4.2.2.2. Also careful consideration needs to be given to the impact of the recommended arrangements on EnergyAustralia's current approach to connection of customers of all sizes and types.		
Recommendation 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.	This recommendation requires firstly an acknowledgment that services should not be classified as negotiated merely because they have the potential to have negotiable aspects. There is a limited degree of negotiation with customers surrounding most aspects of connection to the network and these assets later form part of the electrical system and provide "standard control services" to the original and other customers.
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.	Compliance with to Chapter 5 is mandatory for Registered Participants (RPs) only, why include others. Such details should be included in Code of Practice type of documents
Recommendation 12	The NER should define the standard connection services to apply to micro DGs.	Inclusion of details of non-Registered Participants is not desirable, NER (chapter 5) should remain focused on RPs & may be used as a Guide only for non-RPs
Recommendation 13	The NER should set out the minimum content for standard applications in a schedule to Chapter 5.	
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	Is there provision for a deemed standard contract to apply as soon as connection services such as Design are commenced? How does a DNSP control the number of days which may be required by a contestable service provider to complete the connection?

	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.	Rather than minimum content it would be preferable for the Rules to specify a model contract, this would then obviate the need for the AER to approve contracts which adopt the model and leave the AER's approval role to those which vary from the model. Further and careful consideration needs to be given to the appropriate time frames and allowance made for matters which are performed on a contestable basis and are therefore outside the control of DNSPs. EnergyAustralia has already developed its own Standard Generator Connection Agreement (SGCA) based on the NER which includes "Latest Ready for Connection Date". There is no need for AER approval
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	Again the paper struggles with the interaction between negotiation surrounding the connection and the classification of this service for economic regulation. The classification of services for DNSPs needs revision. Indeed, if the outcome of this process is that every connection to the network is a negotiated service and subject to Rules separate from direct control services, the result would be devastating for DNSPs and customers alike. Clarification is needed as to what is really meant by some words in this recommendation - particularly a mutual understanding of "negotiated" and its implications - vulnerable users - cooling off period - exchange of "commercial information". Draft Rule 6.7.5 has not been sighted Rule 6.7.5(c) has not been sighted All these sub-recommendations are already covered in EA's

	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.
		SGCA, cooling off period is not required as a formal "Offer to Connect" would be valid for a specified period. Such details should be included in a separate "Explanatory" type of document and not be part of the main Rules
		
		It is not apparent why a cooling off period would be required in relation to these arrangements if they do not apply to small retail load customers. Even if they do apply to small retail load customers, there is no justification in the paper for the application of a cooling off period to connection arrangements. Unlike retail contracts these are not contracts which are entered into "on the spot" or under any type of pressure. The arrangements applied to customers would be largely standard and most likely to be contestable. In the unlikely event that the DNSP would be seeking to levy a charge, these would be either with subject to some form of regulation or subject to arbitration if negotiated. This comment also applies to recommendation 16.
		
		The negotiation framework is not a new concept and EA already has such documents.

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	There is no justification for the inclusion of non-Registered Participants Already there is no compulsion, hence no need of cooling off period. There is already a provision in EA's SGCA for amendments with mutual consent

	technical conditions which may require NEMMCO involvement) and where those changes have no associated cost effects.	

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.
		As above.
		
		Five days is unlikely to be sufficient time if all or even the majority of new connections are to be processed through this framework. These are not inquiries which can be managed en masse. EnergyAustralia suggests that the target time should be as soon as practicable but respond within 10 business days of receiving an initial inquiry if the response to the inquiry will take longer than 30 days.
		
		This recommendation fails to recognise the contestability arrangements applying in NSW, where the customer (or their retailer) is at liberty to arrange a connection with either an ASP or the contestable limb of a DNSP (this contestable limb is ring fenced from the DNSP's regulated activities in NSW). Whichever approach is chosen, there may be a limited degree of negotiation concerning the physical and technical attributes of the connection.
		
		Further and detailed consideration needs to be given to what distinguishes a standard contract with a negotiated contract and that this will not be determined by reference to whether the service is classified as negotiated or direct control for economic regulatory purposes.
		
		There needs to be recognition that the arrangements which are put in place at the time of connection and for which there may need to be some negotiation are quite separate from the treatment of the services provided through that connection over the long term. The need for some negotiation at the time

		of connection does not mean that a negotiated service is being provided. As regards standard and negotiated contracts it is likely that there will need to be some element of negotiation of technical issues with respect to all contracts, however the general terms and conditions could be fairly standard. All the timelines & exchange of requisite information is being followed as per the Rules, no need to repeat. Already available through the use of published loss factors. Estimates of site specific loss factors should be able to be provided through reference to other like loads in the supply region
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.	As above. It is for the DNSP to advise all the connection requirements during the Planning & Investigation phase.
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.	Similar to recommendation 17, five days is unlikely to be sufficient time to provide detailed technical information where large numbers of connection applications are being received. Standard connection application route is applicable to non-Registered Participants, therefore, NER timelines are not mandatory.
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.	Similar to recommendation 17, this time frame does not seem adequate. Standard application form is used by non-Registered Participants, therefore, NER timelines are not mandatory.

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.	Should best be left to the DNSP to decide on a case by case basis.
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.	The paper fails to recognise that in the vast majority of cases, connections to the network are contestable and undertaken by parties other than the DNSP. As part of the connection process however the connection assets (once completed) are contributed to the DNSP and incorporated into the assets which provide a use of system service (however the DNSP receives no regulated return for contributed assets). This paper becomes quite confused around the economic arrangements associated with distribution connection. On one hand it seems to want to regulate services which are currently contestable. On the other hand it wishes to remove some standard control services into a negotiated framework. This needs further consideration and clarification. During Connection Enquiry stage all the necessary information is exchanged, much before a formal application is lodged.
Recommendation 23	The NER should: ▪ combine the technical, price and non-price negotiation phases currently set out in the application for connection and offer to connect phases; ▪ remove any provisions which will be captured in the negotiation framework specified in Rule 6.7.5; ▪ require the DNSP to commence negotiations with the user as soon as it submits a completed application form; and ▪ require both the DNSP and user to negotiate in good faith ▪ state that any negotiation relating to access standards must:	Refer recommendation 22. This requires a rethink of the current classification of distribution services, which is warranted. Already being followed as per the Rules, why repeat. Rule 6.7.5 has not been sighted. Pricing as it relates to direct control services is a regulated function that is not be subject to negotiation.

	▪ 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. ▪ 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.	
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.	Should best be left to the DNSP to decide on a case by case basis.
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.	Agree with permitting the recovery of capital contributions and receiving contributed assets, which mirrors existing NSW practice. However, strongly disagree that a different form of regulation should apply to connection assets which upon completion form part of the network and provide standard control services both to the original customer and subsequent customers that connect to it. Such an approach will create orphaned assets under a new negotiated asset class with differing regulatory arrangements. This could potentially leave customers at risk of having certain responsibilities for their connection assets, which differ from upstream assets

		which supply them.
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.	Never charging for shared assets is contrary to current regulation - second sentence needs clarification. Recommendation 27 represents an important change to the current arrangements in NSW where there is some (although limited under the IPART determination) scope to recover costs for augmenting the shared network in circumstances where it is warranted. Consideration needs to be given to the implications of managing system constraints created by generators with a right to connect but who determine not to pay for upstream augmentation, through connection agreements, see discussion on pages 82-85 of the paper. It is proposed that there be no obligation upon the DNSP to augment the shared network to enhance network capability to handle the proposed generator load unless the generator volunteers to pay, but this leave the DNSP to manage the constraints created contractually. This is clearly inappropriate, if the approach is adopted, the Rules will need to impose an obligation upon such generators to comply with the constraints imposed such that it would be a breach of the Rules if they are not complied with.
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	This recommendation does not recognise that often a connection charge will not be levied but rather that the customer will be required to engage an accredited service provider to carry out the works, no money changes hands between the customer and DNSP but the customer does pay

	charge may be levied; and ▪ a definition of the relevant connection point.	for the dedicated connection asset and it is vested with the DNSP who operates and maintains, and eventually replaces the asset.
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.	This will vastly complicate administration and the regulated income if applied to all connection assets - the new customer may not be liable to pay anything under recommendation 25 so the DNSP will be exposed. This arrangement would only be acceptable if it operates in a similar way to that current in place in NSW whereby in a very limited number of circumstances the original customer who paid for upstream extension works or a rural connection receives the payment from the later connecting customers, the DNSP being the intermediary for that payment.
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)).	
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.	There will be issues with the calculation of marginal loss factors (MLFs) for generators: • It will be impractical to calculate for a generator size of less than 10MW, because of the large number of calculations involved; • The estimation process for smaller generators will be fraught with uncertainty; • It will not necessarily lead to a favourable outcome for the embedded generator. MLFs can be less than unity; • It would create an inconsistency with loads and settlement issues with combined load/generator options; and • A loss settlement surplus regime would be required for

		the DNSP's territory, with considerable administrative consequence. It is unclear how settlements would even operate. In many instances, DG proponents plan to supply a fixed area, without a Retailer involved. It appears that this will be the dominant business model for the future. In such cases, applying a marginal loss factor is meaningless as such proponents would be buying energy from themselves, leaving themselves with a nett settlement to redistribute to themselves.
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.	This calculation approach would be incompatible with that used at transmission levels, where the loss calculation uses TPRICE. This is the approach used by EnergyAustralia for site specific calculations in the distribution network
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).	The requirements associated with such a DLF calculation can vary significantly depending upon the configuration of the network and loads. Moreover, customers should not be permitted to "cherry pick" between the site specific and average DLF.
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.	This will have an impact on the retail market that will be required to administer a new set of loss factors within a DNSPs supply area, with questionable value gain in light of the NEM objectives. Notwithstanding the above comments, materiality should be defined as more than 20% difference of the overall loss factor for that supply voltage. For example if the LV losses are 5.5%, then a move to a regional losses for LV network should mean each regions LV losses are outside 5.5% +- 1.1%. If this

		matter is to be furthered, a cost benefit analysis should be carried 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.	The generator should by assigned the same loss factor when it is importing, rather than receiving an average DLF when importing as is proposed. This is because that a generator would be receiving the benefit of a marginal loss factor, but if it begins to import, the benefit afforded of receiving a MLF is lost by the DNSP in congestion reduction. It should be noted that only one meter is required with import/export capability. Comments to this item are written on the assumption that import means energy flowing from the network connection point to the customer and visa-versa for export. That is, the customer load and generation are below the connection point and only seen by the DNSP on a combined basis.
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.	DNSPs have minimal control of losses on the network. Losses are one factor in building the electricity network, but not the only one, and weather is the dominant driver in levels of losses. It is meaningless to place incentive on DNSPs with respect to losses when losses are mostly driven by weather and not DNSP behaviour. IPART failed in 1996 to establish a loss incentive (it was initially the wrong way round, was reversed in 1997, and was in any case unworkable). There is significant year on year variation and hence the need for either averaging or an accrual process The solution to ensuring losses are taken into account appropriately in planning is to require the use of the cost of losses at appropriate LRMC rates in planning wherever loss is significant (recognising that for the vast majority of EA's planning, losses are not material in the decision making, only

		sometimes when comparing different voltage, say 132 kV and 33 kV alternatives).

Case Study – Demand Management Projects

Since the introduction of IPART's demand management incentive regime, EnergyAustralia has undertaken 17 demand management projects that have cost effectively reduced network expenditures. These include five embedded generation projects, nine customer power factor correction projects, one commercial energy efficiency program, a residential lighting project and a commercial interruptibility contract.

Despite undertaking public consultation processes seeking options for investigation, development or implementation in most cases, all but two of these have arisen solely from internal project identification and development processes.

The embedded generation projects involved EnergyAustralia leasing generators from service providers who responded to an invitation to quote for provision of such generation facilities. These projects have proven highly flexible and cost effective in certain locations, and were developed through an in house analysis of the opportunities and options. While extremely competent at providing temporary embedded generation solutions, the service providers would not have responded to generalised calls for demand management options.

The customer power factor correction projects have proven to be our most cost effective demand management options. We established a head contract for supply and installation of suitable equipment under tender and implemented projects to identify customers in the target areas who could benefit from power factor correction and offered project facilitation and the benefits of our centralised buying power. This has proven much more cost effective than customer by customer subsidisation of installations, and achieved customer conversion rates of up to 90%. This project approach was developed in house through a careful analysis of the failures and barriers in the power factor correction market and design of a program approach that directly addressed them. This project could not have been developed by a third party in response to an RFP. Subsequent to our developing this program and implementing it with over 100 customers, we have noted some of our service providers proposing similar approaches. However, the cost structure has not been as cost effective as our in house programs.

The commercial interruptibility contract was developed by one of our in house investigations, which identified the opportunity at a customer visit. A public consultation process had not identified this opportunity and our experience to date with service providers offering to work in this field has not led to any viable projects.

The residential lighting project was developed in conjunction with a service provider after they responded to our public consultation invitation. We jointly developed the initial concept into a project that would deliver the necessary certainty and focus to enable deferral of a network investment. Without this negotiation and development phase, the proponent would not have been able to develop a project that would have been successful.

The commercial energy efficiency project was one of our earliest DM projects and was implemented using a public standard offer of $200/kVA for demand reductions in a specific area. It was developed with the target of achieving 1.2MVA of demand reduction based on a submission from the former NSW Sustainable Energy Development Authority. After the offer had been open for 11 months, it delivered a very small demand reduction from a small number of projects. It was evident that effective demand management would require much more facilitation if we were to be able to have any certainty of delivery.

Conclusions

A review of EnergyAustralia's successful demand management projects to date suggests that none would have arisen in response to an RFP of the sort envisaged by the NSW DM Code.

To ensure EnergyAustralia's continued ability to utilise effective demand management projects, we would need to continue with a process substantially similar to our current method in parallel with the RFP regime.

This would be essential to ensure development of the service provider community, identification of opportunities and maintenance of cost pressures on the limited number of suppliers in the market.

Case Study – Demand Management Reasonableness

EnergyAustralia's network investment governance process includes consideration of demand management options for all demand driven investments with an estimated capital cost above $1m. The initial part of the DM investigation process is to undertake a formal screening test, which documents the investment drivers and DM requirements that would enable a saving in costs (primarily through deferral of capital expenditure). This determines whether it is prudent to invest further resources in identifying DM options, and reflects the condition in our DNSP licence:

> "1.1 Before expanding its distribution system or the capacity of its distribution system, the Licence Holder must carry out investigations (being investigations to ascertain whether it would be cost effective to avoid or postpone the expansion by implementing demand management strategies) in circumstances in which it would be reasonable to expect that it would be cost effective to avoid or postpone the expansion by implementing such strategies"

The reports are published regularly on our website.

In 2006/07, we completed 34 such DM screening tests, of which five went forward to detailed investigations. Examples of some of those that did not proceed are outlined below.

1. Kooragang Island / Waratah STS

This is a $77m development involving the construction of a new subtransmission station on Kooragang Island and a new Zone substation at Jesmond, near Newcastle. Load in the area is currently supplied for the Waratah subtransmission station, but it has reached the end of its economic life and must be retired soon. In addition, substantial additional load is forecast in the area, mainly driven by industrial development. This investment strategy allows for this retirement and enables future load growth to be accommodated.

This investment strategy was the most economic means of resolving the replacement issues under a range of scenarios, including those that included no load growth due to the achievement of significant levels of demand management. On this basis, no savings were able to be achieved by using demand management and the report concluded that no further consideration of demand management options was warranted.

2. St Ives 11kV feeders 5 & 12

This project is driven by the loading on the existing feeders. This system is designed so that, in the event of an outage of one of the feeders, the load can be picked up by the other to restore supply to customers within the four hours. It supplies a mixed commercial and residential load that was forecast to increase due to underlying growth and a substantial new customer. The supply side solution was the installation of a new feeder at a cost of $2.1m.

Our analysis showed that in order to defer this project by one year, the load on the feeders would need to be reduced by 3.3MVA or 42% of the existing load. The cost saving arising from a one year deferral would be only $168,000 – equivalent to $50/kVA of demand reduction. Based on our experience, very few demand reduction options exist with costs less than $200/kVA. Given the very large percentage of the existing load that would need to be reduced and the quite low value of the reduction, we concluded that it was not reasonable to expect that it would be cost-effective to postpone the proposed supply-side solution by implementing demand management strategies.

3. New 33kV feeder from Tomago STS to Williamtown zone substation

This $4m investment will provide a new 33kV connection between Tomago sub-transmission substation and the Williamtown zone substation to form part of the 33kV network supplying the Port Stephens area.

Our analysis showed that demand in the area would need to be reduced by 25MVA in order to defer the need for this investment by one year, and that such a deferral would result in a cost saving of $330,000. As this represents a value of only $13/kVA, it was considered unreasonable to expect that such a large amount of demand management would be found at such an extremely low cost.

Conclusions

There are frequent occasions when the circumstances in which network augmentations occur mean that demand management solutions are extremely unlikely to be viable. This can be because other investment drivers, such as replacement of aged assets predominate, because the size of the demand reduction relative to the existing demand in the area is very large, or because the supply side solution is extremely cost effective.

Undertaking a full RFP process for any of these examples would prove not only wasteful of DNSP resources, but discourage the few demand management service providers that exist in this emerging market.

Case Study – Large Load Customers

The Large Load Customer (LLC) provisions under the NSW Capital Contributions provisions allow for attributing augmentation costs for a portion of the shared network to be charged to customers that clearly drive that augmentation. By setting a high bar that the customer must be at least 50% of the nameplate rating of the existing shared asset needing augmentation, the issue of the last MW load growth that finally forces augmentation, AKA the "straw that broke the camels back" does not arise.

EnergyAustralia invoked the LLC provision for a customer that requested a substantial amount of load at the end of a peninsula. The existing load was substantially domestic and was adequately supplied by a radial 11kV feeder. The new customer, at the end of this feeder requested additional load that represented well over 50% of the rating of the feeder. To supply this load, the local 11kV feeder would have required a doubling of its capacity. In effect, a new feeder needed to be built to supply the large load. If there had only been incremental load growth to the area, only a few small portions of the feeder would have required upgrading over time.

If the LCC provisions were not in place, this customer would have received the available capacity at minimal cost (excepting the dedicated component of their supply) with other customers paying for the upgrade that they did not require. Indeed, the size of the load meant that the upgrade to the shared 11kV supply was almost a dedicated supply with some additional load from the local area. If the customer had been the first customer in the area, they would have paid for the supply, and then received reimbursement as new load arrived. But they would have only received a small amount of reimbursement, as the additional load was small in comparison. By coming later, they would have been much better off if the LLC provisions were not in place.

As it turned out, since the customer was going to be required to fund the shared augmentation costs, the customer reduced its load requirement to below the 50% rule. The rule worked (as intended) by incentivising the customer to carefully review the amount of load it really required. As a result, the proposed augmentation was scaled back substantially, and although other customers still pay for the augmentation costs that still needed to take place through tariffs, the burden on them was greatly reduced. The large load provisions drove a more efficient investment outcome.

It has been suggested that locational marginal pricing would deliver the correct signals to proposed new loads, such as this example above. However, marginal cost pricing relies on signaling increments of load growth. Indeed, even if a long run signal was taken, which signaled the next piece of augmentation work, there are discontinuous steps of cost when considering each network piece of upgrade work on this 11kV feeder. What is the marginal cost: is it to supply an additional 500kVA, or an additional 2MVA. Both could be supplied from the existing shared 11kV supply, but at markedly differing costs. Converting these costs to a $ per kVA does not deliver the same variable rate, since construction costs do not exhibit smooth continuity.

Local conditions such as these cannot efficiently be reflected in a locational tariff to signal forward costs. Rather, consumption tariffs need to reflect broader averages of the network LRMC. However to encourage efficient network development, this background pricing signal must be supplemented by:

- locational prices through capital contribution rules (including LLC provisions); and
- demand management, which in general targets shorter run opportunities for the deferral of network augmentation on an area and site specific basis.

Case Study - Connections Regime

Consider a developer seeking to connect an industrial estate to the distribution network within a local suburb. The industrial estate will require connection at high voltage. The nearest connection point to the higher voltage network is located 5 kilometres from the proposed industrial site. The developer would prefer the connection to be made to the low voltage network adjacent to the site.

Current Arrangements in New South Wales

Under current arrangements in New South Wales, a connection application would be made to the DNSP who would respond with the requirements for connection. The DNSP would respond with what it believes is the most economically efficient solution for that connection. For example, the DNSP may consider upgrading the low voltage network adjacent to the site. Under the current IPART determination in relation to capital contributions[2], the developer would be responsible for that portion of the network extensions or augmentation that is dedicated to the applicant and is not useful in the foreseeable future for other customers. Network augmentation that is of benefit to other customers is funded by EA (except where a defined "Large Load Customer" (LLC) provision applies). There is scope for a greater sharing of costs if it can be evidenced that load growth in the area would warrant augmentation to the existing network in the short to medium term.

Once the basic design characteristics are agreed between parties, connection works for dedicated assets are contestable. That means the developer can tender the works to a number of accredited service providers whether the customer is connected to the high voltage or low voltage network.

The cost of the connection works under either scenario would therefore be paid by the developer to the ASP that undertook the connection works (ie the DNSP does not "charge" the developer).

Once the connection was established, under the current arrangements those assets are almost always "contributed to the DNSP". This means that the DNSP receives the connection assets for nil consideration. Importantly however the DNSP takes responsibility for the connection as part of its use of system service provision. Thereafter, the ongoing maintenance and eventual replacement of the connection assets is the responsibility of the DNSP.

Under the Exception Rule for Rural Customers or LLCs, if another customer or developer connects to the network and makes use of the HV network augmentation of what was an already shared network within a period of 7 years, the DNSP is required to recover a portion of the cost from the second customer and reimburse it to the first, in accordance with a specified formula.

From an economic perspective, the DNSP earns no regulated return on the contributed asset but is entitled to recover any ongoing costs associated with maintenance or replacement as part of its standard service provision. The capital cost of such connection assets is thus not recovered through network tariffs, which recover the upstream infrastructure costs from customers on a standardised basis.

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[2] IPART Determination "Capital Contributions and Repayments for Connections to electricity Distribution Networks in New South Wales", April 2002.

Concerns with ACG/NERA approach

The paper proposes that in the future, connections such as these would be a negotiated service and therefore the future replacement or ongoing maintenance of these connection assets would be outside the standard service provision undertaken by DNSPs. This is a concerning development. It is likely that the developer will not be the ultimate recipient of the service. Instead they will on-sell the development. Nevertheless, the negotiated service will need to be made with the developer.

As these assets will never form part of the RAB the negotiated arrangement will need to include provision for future maintenance and replacement of the asset. There will need to be specific "buy back" clauses if the asset is required for future loads. Most importantly, the precise terms of the service agreement are likely to be with the developer, not with the ultimate end user.

It is important to recognise that EnergyAustralia makes approximately 12,000 connections to its network per annum. A departure from the standardised arrangements currently in place to a regime of individual negotiation would impose prohibitive administrative overheads.

In summary, we are concerned with the proposed movement away from the existing arrangements in New South Wales and would need to be convinced that there is net benefit to consumers in moving to an alternative regulatory approach to regulated assets.

There are other issues which the ACG/NERA approach raise that will need to be resolved:

- The paper's terminology box explicitly excludes reference to "contributed" assets. It seems to fail to recognise that DNSP's will not "charge" connection applicants for connection. Rather the dedicated assets will be contributed to the DNSP.
- The paper alludes to the fact that small customers should not pay any charge for new connections. Under a contestable regime it is difficult to see how this would be workable.
- The paper refers to the allowance of a cooling off period for connection services. It is difficult to understand how this fits with a contestability regime and whether cooling off periods are appropriate at all for proposed connections to an electricity distribution network.
- The implications of separate connections to a connection asset become more complex under a negotiated service. Such provisions would need to be explicit in the service contract.
- The "large load" customer provision in IPART's determination should be retained and considered for any national regime, as it provides an important price signal at the time when the customer's equipment and consumption needs are being specified[3]

[3] This may best be illustrated by an example. In one instance, a potential LLC was located on a peninsula would have been faced with a cost of some millions of dollars to upgrade the High Voltage network. This customer reviewed its load requirement and as a consequence neither the customer nor the DNSP was required to reinforce the network.