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SUBMISSION

Review of the Electricity Transmission Revenue and Pricing Rules: Revenue Requirements

Issues Paper

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Review of the Electricity Transmission Revenue and Pricing Rules:
Revenue Requirements

1. Introduction

1.1 Key themes

Total Environment Centre welcomes the opportunity for further input to the Review of the Electricity Transmission Revenue and Pricing Rules (the Review). This submission builds on our previous response to the AEMC's Scoping Paper on this subject. Where possible, we have addressed the questions framed within the Issue Paper on Revenue Requirements on the basis of our particular concerns, with a focus on the key themes identified by the AEMC:

> *Key themes raised in submissions include the need for regulatory arrangements that achieve a better alignment between investments in and operation of transmission networks and the interests of market participants and electricity consumers. A second important theme is the desire to provide greater clarity, certainty and consistency in the application of regulation.*[1]

Total Environment Centre (TEC) further endorses the introductory statements that,

> *Effective incentives and processes should work towards reducing or eliminating network constraints, where it is efficient to do so and thereby contribute to efficient operational and pricing outcomes in the wholesale and retail markets.*
>
> *Effective incentives and processes also need to give sufficient weight to transmission alternatives, such as embedded generation or demand management initiatives and alternative energy sources.* [2]

This Review is particularly important while new systems are being set in place. The restructuring of the National Electricity Market (NEM) will clearly take some time to achieve, especially considering that the Rules themselves have only just taken effect in their new form. Moreover, it is clear that the whole new area of distribution and retail coming under the sphere of the Australian Energy Regulator (AER), not to mention the addition of the regulation of gas, will inevitably lead to some upheaval within the administration of the new system. This possibility is exacerbated by the current differential in context across the jurisdictions.

However, the current approach to the Review is a piecemeal one, as we have pointed out before in this context.[3] In order to make transmission network investments more timely and efficient it is necessary to first consider energy services from the perspective of

[1] Australian Energy Market Commission, *Review of the Electricity Transmission Revenue and Pricing Rules – Revenue Requirements: Issues Paper*, October 2005, p 7
[2] Ibid., p 10
[3] Total Environment Centre, *Submission: Review of the Electricity Transmission Revenue Pricing Rules Scoping Paper*, August 2005

consumers – what do they need and how can this need be delivered at the lowest cost (including environmental and social costs)? Such a review should work its way up through retail, distribution and transmission networks and generation to comprehend how best these can be regulated to deliver the desired outcomes.

We reiterate that the current transmission network revenue Rules are inappropriately focused on the supply of electricity at the expense of a focus on the provision of energy services, including demand side or other non-network approaches. This focus has resulted in:

- enormous and unnecessary costs of inefficient network investment;
- the erasure of accurate price signals at multiple points throughout the NEM, including transmission networks;
- barriers to distributed generators and demand management (DM) providers; and,
- a greenhouse gas emission intense electricity system that brings with it a disproportionate risk of future carbon liabilities.[4]

1.2 Demand management and the NEM

DM [5] must be recognised as a preferable alternative to augmentation by the AEMC, the AER and the transmission network service providers (TNSPs) because of the massive benefits that it delivers to consumers. With the system in a state of flux, now is the time to set the foundation for the future.

Economic efficiency is central to the NEM. To achieve this there must be equal emphasis on demand and supply as the basis of standard economic regulation. DM and energy efficiency must therefore be given high priority and be integrated in uniform national regulation.

The importance of enhancing DM in the NEM has been repeatedly highlighted by the Council of Australian Governments (COAG) and the Ministerial Council on Energy (MCE) over many years. As early as 1992, the National Grid Management Protocol recognised the importance of DM as integral to the creation of an efficient and cost-effective electricity system.[6] In 2002, the Parer Report[7] again emphasised the importance of demand management and recommended several measures to improve demand side participation. Subsequent MCE communiqués over 2004 and 2005 have specifically highlighted the need for greater energy efficiency. More recently, the Commonwealth has also emphasised the importance of DM: "To improve Australia's energy efficiency

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[4] Ibid.
[5] DM in this submission can be read to include 'demand response', 'demand-side management', 'demand side response', 'energy efficiency' and 'non-network solutions'. In general, DM can include both the management of peak loads and energy efficiency as a way of meeting capacity requirements most cost effectively. It includes a diverse array of activities that meet energy needs, including cogeneration, standby generation, fuel switching, interruptible customer contracts, and other load shifting mechanisms.
[6] National Grid Management Council, *National Grid Protocol*, First Issue, December 1992
[7] Commonwealth of Australia, *Towards a Truly National and Efficient Energy Market*, 2002, p 33

performance, the Australian Government will: improve price signals for demand side management as part of reforming Australia's energy markets ..." [8]

Further, the National Electricity Rules state that: "The regulatory regime to be administered by the AER must ... also have regard to the need to:

> (1) provide Transmission Network Service Providers with incentives and reasonable opportunities to increase efficiency;
>
> (2) create an environment in which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration;" [9]

Demand management is traditionally, "defined as one of a number of ways in which suppliers of a resource can meet their customers' energy needs by either shifting or reducing their demand."[10] The Independent Pricing and Regulatory Tribunal of New South Wales (IPART) Demand Management Inquiry Report points out benefits of DM such as, "lower greenhouse gas emissions, improved utilization of generation, transmission and distribution assets, enhanced network capacity and reliability, lower capital costs, and lower costs to end-users."[11]

A primary advantage of DM is the facility to ease the load on the system. As an alternative to augmentation, DM has the potential to reduce both the quantity and price of electricity used. Better utilisation of existing assets and deferral of the need for new capital expenditure (and consequently operating expenditure as well) by the TNSPs can be gained through reversing the increasing 'peakiness' of electricity use. This peakiness is results in the inefficient utilisation of transmission network assets and is exemplified by EnergyAustralia's claim that "the top 10 per cent of capacity is utilized less than one per cent of the time ..."[12]

The proposed Wollar to Wellington transmission line provides a case in point, of an arguable decision about whether augmentation of the back-up line will indeed bring sufficient public benefit to outweigh the potential gains from demand management. In the face of peak demand growth of only 8MW[13], the proposed line has a massive capacity of between 1000MW and 2000MW. It is a prime example of where, in meeting an alleged need, it is probable there will be vast under-utilisation of the infrastructure, and hence a highly inefficient business decision (which contravenes the spirit of the NEL). Higher than appropriate costs for the service delivered and market distortions will result, in turn substituting inefficient network service provision for more cost-effective solutions to system constraints. In this context, TransGrid's conclusion that non-network alternatives are not cost-effective is extremely inappropriate. TEC has previously argued to the ACCC, and in response to TransGrid's EIS for the line, that the potential revenue should be

[8] Commonwealth of Australia, *Securing Australia's Energy Future*, 2004, p 105
[9] National Electricity Rules, Section 6.2.3
[10] Independent Pricing and Regulatory Tribunal of New South Wales, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services – Final Report*, October 2002, p 3
[11] Ibid., p 3
[12] Ibid., p 60
[13] TransGrid and Country Energy, *Development of Electricity Supply in the Western Area of NSW – Final Report*, August 2003, p 9

disallowed on this basis, and DM and/or DG solutions pursued. This example can be considered as an example of “gold plating”, that is, the artificial inflation of a network's revenues through investment in uneconomic regulated assets.

The NSW *Electricity Act 1995* imposes the necessity for the investigation of DM alternatives in the licensing system. The Act states:

> *(5) Without limitation, the Minister must impose the following conditions on each electricity distributor’s licence:*
>
>> *(a) a condition requiring the holder of the licence, before expanding its distribution system or the capacity of its distribution system, to 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,*

A similar condition should be required of TNSPs, with the added obligation to **implement** such actions where they are cost effective.

1.3 Need for transparency and certainty

A key theme of the issues paper is certainty of regulation. A core requirement therefore is transparency of decision making. TNSPs and the AER must increase the transparency of the planning and regulatory processes in which revenue requirements are determined, as consumers ultimately pay for transmission services and can benefit from the implementation of demand management instead of augmentation.

1.4 Scope of this submission

We have focused on specific issues of concern, and addressed them in terms of the questions posed in the paper. This has meant some reordering of the questions, but in general we have followed the order of the AEMC paper. The discussion below addresses:

- Discretionary powers of the AER
- Revenue matters
- Non-network solutions
- Disclosure of information

2. Discretionary powers of the AER

Question 1. Should the Rules specify the form of regulation for prescribed transmission services (as currently) or leave this open for the AER to determine?

The regulation of transmission networks has occurred because networks are natural monopolies. As such, obtaining greater efficiencies from their investment and operation must be a principal goal of regulation.[14]

The current form of regulation addresses this intent in the form of regulation of a revenue cap applying the CPI-X building block approach to maximum allowable revenue. We support the form of the regulation, if not all the details therein. While the revenue cap provides a greater overall incentive than a price cap for DM, there should be more incentives provided to encourage DM. If incentives for demand management are adopted, however, they could be undermined by other forms of regulation (such as a price cap). We are in favour of clear directions being set out in the Rules, to promote certainty for all stakeholders. This also applies to:

> *Question 3. To what extent do the alternative forms of regulation identified above, warrant further investigation and analysis in the course of the Review?*
>
> *Question 4. Should the Rules provide the flexibility to adopt alternative forms of regulation in appropriate circumstances, and if so, what are those circumstances?*
>
> *Question 5. Are there any additional forms of regulation that should be considered?*

Question 6. To what extent does the degree of TNSPs' market power differ for different transmission services? To what extent are transmission customers able to act in a way that constrains the conduct of TNSPs?

TNSPs wield considerable market power and form natural monopolies, thus creating barriers to alternatives such as embedded generation and the range of demand management options. There is little constraint in the opposite direction. Therefore, to reduce regulation of the TNSPs would allow the further entrenchment of their monopoly (as exemplified by the fact that there is effectively one TNSP per jurisdiction, with a handful of MNSPs). The form of regulation should be retained. This also applies to:

> *Question 7. Would a multi-layered regulatory approach, based on degrees of market power associated with different services, be appropriate?*
>
> *Question 8. Are there transmission services that are likely to be suitable for a less intrusive form of regulation, such as price monitoring?*

Question 92. What should be taken into account in determining the appropriate degree of regulatory discretion? What are the advantages and disadvantages in leaving a wide degree of discretion for the AER? What are the arguments for and against a more

[14] Gavan McDonell, *COAG's Quandary: What to do with the Energy Markets Reform Program?* February 2005, p 35

prescriptive approach? Alternatively, should the Rules prescribe/confer discretion in a way that is more tailored to the specific decisions that must be made?

As a general principle, matters of importance ought to be addressed within the Rules, rather than left to the discretion of the AER. Light-handed regulation can lead to a lack of certainty for stakeholders. The Rules should therefore give precise guidelines to the AER in its decision-making capacity. To ensure transparency and certainty, there needs to be a consistent application of principles to decisions. This is not only reassuring for consumers but also respects the needs of business. In addition, certainty is essential for those contemplating future investment in an industry that involves high capital and operating expenditures.

Question 94. Given that regulatory practice and methodology will evolve over time, to what extent should the Rules accommodate future change without the need for progressive amendments? Alternatively, is it preferable that future changes in approach be implemented via a future Rule change process?

We reiterate our argument about discretion: it is preferable to go through the process of a formal Rule change, with all its checks and balances, where the matter is deemed sufficiently significant. This would increase the level of transparency and public involvement in key regulatory decision making.

Question 97. What are the relative advantages and disadvantages of an approach that specifies outcomes and principles as decision making criteria in the Rules, versus Rules with greater prescription and detail?

Although the current system as a whole is already fairly prescriptive, there remain significant barriers to non-network solutions and the wider entry of embedded generation and renewable energy technologies. Thus TEC would argue for greater delineation of expectations, rather than less. Leaving decisions to be made by the AER on the basis of outcomes and principles leaves us with the status quo, and also contributes to the climate of uncertainty reported in the AEMC paper.

These arguments also apply to:

> *Question 98. What is the appropriate balance between fixed procedures and leaving procedural requirements open to discretion in relation to setting revenue determinations, and for related regulatory functions eg assessing compliance with price controls?*

3. Revenue matters

3.1 Revenue cap

Total Environment Centre fully supports the retention of the revenue cap method of assessment, since it is an important means of encouraging networks to carry out their investments prudently. Without such a cap, networks have a reduced incentive to carry out their operations within budget, and could instead seek to encourage greater consumption of electricity.

TEC also recommends that the revenue cap is applied to DNSPs in the future regulation of distribution networks by the AER, for the same reasons set out above for transmission networks. Our arguments in Section 2 concerning the need to limit the discretionary approach are relevant here.

3.2 Incentives for DM under a revenue cap

A revenue cap alone will not necessarily increase the uptake of cost-effective DM opportunities. Added incentives for DM are needed, and we discuss a variety of these in Section 4, Question 43 (incentive mechanisms for DM).

3.3 Incentives for DM under a price cap

As a second preference, any price cap system must include incentives for DM to counter the massive incentives and cultural bias for TNSPs to sell more electricity. Such incentives should ensure that networks are able to recoup revenue for both the cost of carrying out demand management and for the lost revenue of sales that would have been made had an augmentation gone ahead. The purpose is promote consideration of more efficient non-network solutions and, conversely, to reduce the incentive for the networks to encourage excessive consumption (that is, by selling more electricity). If there is a change in the system from a revenue cap to a price cap, then a further incentive must be provided for TNSPs to investigate and implement demand management. Again, there is a useful model in NSW, the "D-factor". See further discussion of the D-factor in Question 43 (section 4 – incentive mechanisms for DM).

3.4 Clarity in the recovery of spending on DM

There is currently a lack of clarity from regulators regarding the recovery of DM spending. This creates uncertainty for networks investigating DM solutions to network constraints. ***The national regulator should therefore clearly set out the circumstances in which networks can recover the costs of implementing DM.*** There is currently no guidance for the treatment of expenditure on non-network solutions to transmission constraints. This issue has been identified repeatedly as one of the key barriers to investment in non-network solutions. To encourage TNSPs to undertake cost-effective expenditure on non-network solutions there is clearly a need to provide certainty as to the way in which those expenditures will be treated and the rate of return that those expenditures could be expected to deliver.

3.5 Network planning

National regulation must ensure that demand management is fully investigated before the undertaking of network expansions, and implemented where it is found to be more cost effective. This issue should be addressed in network expansion rules and in network planning rules. When assessing the relative costs and benefits of network augmentation compared to the deferral of network expansions, costs and benefits should include:

- Annual operating cost of the augmentation / deferred augmentation
- Total annual net cost of servicing the capital expenditure of the augmentation / deferred augmentation, such as financing charges and capital depreciation.

3.6 Reporting

NSW currently requires distribution networks to investigate and report on cost-effective non-network solutions to network constraints. The guidance for compliance with this licence condition is provided by the NSW DM Code of Practice (see Attachment 1).

The national regulator should adopt these reporting requirements to improve the consideration of non-network solutions and, in turn, reduce unnecessary costs for consumers. In addition, the regulator should improve on these requirements by ensuring that network monopolies **implement** DM opportunities when they are found to be more cost-effective than network augmentation. In a competitive market, the failure of networks to weigh up non-network and alternative generation options goes against the intentions of the National Electricity Law and adds unnecessary costs for consumers.

Question 13. Are there concerns with the current operation of the revenue caps applied to TNSPs? If so, what changes would be appropriate to overcome these problems?

Total Environment Centre has consistently supported a revenue cap with extra incentives for DM, such as the facility for a set-aside percentage for demand management. A revenue cap provides greater incentive for consideration of non-network solutions since the network can absorb the savings of augmentation deferrals, while allowing for flexibility in pricing. A price cap, in contrast, rewards networks for more electricity sales, and does not impose limitations on network augmentations even when more cost-effective alternatives are available.

A critical problem with price cap regulation is the lost incentive for non-network solutions to transmission constraints. As Gavan McDonell points out:

> One of the most deficient aspects of price cap regulation is that it *provides the incentives to increase the transport of energy through the grid,* since the greater the quantity of energy moved, the greater the revenue and hence the opportunity for profits. That is, *this system of regulation provides direct incentives both to increase industry's economic costs* and *to encourage greater household demand.*[15]

These arguments also apply to:

> *Question 15. Should the Rules continue to be prescriptive in relation to the form of direct or indirect price control to be adopted by the AER for the TNSPs? If so, what form of price control should be prescribed?*
>
> *Question 16. Alternatively would there be benefit in allowing the AER guided discretion regarding the form of price control? If so, what guidance would be appropriate?*
>
> *Question 17. What characteristics of electricity transmission are relevant in considering the choice of form of price control? Do these characteristics differ from those for electricity distribution where price caps often apply?*

[15] Gavan McDonell, *COAG's Quandary: What to do with the Energy Markets Reform Program?* February 2005, p 36 (italics in original)

> *Question 18. What factors ought to be taken into account when choosing the form of price control?*
>
> *Question 19. How do the incentives provided under the different forms of price control impact on the efficient development and operation of the transmission system?*
>
> *Question 20. What advantages or disadvantages would there be in allowing greater pricing flexibility for TNSPs under a price cap form of price control?*
>
> *Question 21. What advantages or disadvantages are there in adopting a hybrid form of price control?*

Question 41. What role, if any, should Rules for economic regulation have in providing incentives for TNSPs to avoid inefficient over- or under-investment in network assets?

As noted above, since transmission networks are not required to invest in DM when it is cost effective, there is a strong tendency to focus purely on new infrastructure as an answer to increasing demand. This tendency can be labelled “strategic behaviour” and includes the practice of “gold-plating”. Inappropriate moves to artificially increase revenue include unnecessary expansion of the regulated asset base (RAB) and over-blown demand projections. To ensure that these practices are minimised, if not eliminated, it is critical that the AER undertake meaningful and substantiated assessments of past network investment and disallow recovery of imprudent investment that should have been deferred. Prudency reviews also need to be more transparent and should include failure to undertake DM when cost effective as a reason to disallow capital expenditure.

As noted above, incentive mechanisms for the pass-through of DM costs are needed to counter the inappropriate focus on the supply-side of energy service provision and to limit inefficient over-investment in transmission infrastructure. The absence of incentive mechanisms for the implementation of demand management and other non-network solutions is resulting in inefficient, peak-demand driven transmission infrastructure investments.

The recent ‘D-factor’ [16] incentive mechanism initiated by IPART for DNSPs has helped to spur networks into investigating and carrying out DM solutions. It enables networks to pass-through the costs of DM projects, ensuring an appropriate rate of return on this investment. More broadly, it is helping to create a viable DM provider industry that is able to respond to networks’ calls for DM. The response to the D-factor incentive mechanism in NSW to date is promising, indicating that this approach is a valid means of promoting more efficient network investment.

Question 65. To what extent should the Rules provide guidance to the AER in relation to the determination of efficient capital expenditure?

[16] Independent Pricing and Regulatory Tribunal of New South Wales, *Guidelines on the Application of the D-factor in the Tribunal’s 2004 NSW Electricity Distribution Pricing Determination*, April 2005

The transparent and thorough investigation of DM alternatives to network augmentation should be made clear through the Rules to ensure that these investigations are central to the determination of proposed efficient capital expenditure by the AER.

4. Non-network solutions

As noted above, an efficient, cost-effective electricity supply system should make allowance for solutions other than those that rely entire on network-driven solutions. Demand management in its various forms can indeed be more cost effective, and hence more efficient, thus meeting the NEL objective. Non-network solutions therefore should be given explicit consideration within the Rules.A major issue is the planning processes that TNSPs are required to undertake under the Rules. Currently, TNSPs are not required to solicit proposals for alternative non-network solutions before deciding to augment their networks. This creates a natural barrier for cost-effective non-network solutions and forecloses on the potential for networks to operate more efficiently by avoiding unnecessary or premature network augmentations, and thereby create savings for consumers.

Before TNSPs undertake major network augmentations, they should be required to solicit proposals for alternative non-network solutions. This would involve clear protocols for information disclosure, specification of constraints, requests for proposals, and evaluation of proposals. To facilitate this process, the AEMC and the AER should promote a comprehensive approach through mandatory DM Codes of Practice for network service providers. This would be a key step in facilitating a DM services market. Furthermore, recognising that transaction costs of participating in a request for proposal process would be very high for many small DM opportunities, the AEMC should also promote standing offers for small DM services.

Question 43. Are economic incentives necessary to ensure TNSPs consider both network and non-network solutions (including demand management and other energy sources) to forecast constraints and reliability shortfalls? How could such incentives operate?

Economic incentives are urgently needed to ensure that TNSPs consider non-network solutions before augmenting their networks.

Earmarking a percentage of network spending for DM:

One way of ensuring that networks undertake DM is for regulators to earmark a specific minimum spending level for DM by networks. Given the large technical and economic potential for DM, between 10% and 25% of the projected network capital expenditure should be specifically earmarked for cost-effective DM projects. This funding should be allowed only on "use it or lose it" terms, and could step up from an initial small percentage, increasing as networks become more adept at facilitating DM, then gradually reducing as the potential for DM is utilised.

Clarifying the circumstances in which DM investment can be claimed:

Several networks have rightly noted that there is a lack of clarity regarding the recovery of DM spending by regulators. TransGrid's consultants have argued that uncertainty in the treatment of DM by the ACCC may have deterred them from selecting that option: "Any uncertainty as to the regulatory treatment of DSM-related expenditure by TNSPs has the potential to undermine the practical consideration of such alternatives."[17] Thus there needs to be a proper, considered scheme for treatment of such expenditure when determining acceptable revenue and assessing revenue assets bases.

Incentive mechanism for DM:

What has been applied to some effect in NSW with distribution networks under a price cap is the use of the D-factor. This is essentially an incentive arrangement via IPART for DNSPs to promote the consideration of DM in network planning, with the requirement that, "the DNSPs must demonstrate to the Tribunal that its demand management implementation costs are less or equal to the avoided distribution costs before it can pass through any costs to customers."[18] A similar, but more limited, principle could be applied at a transmission level under a revenue cap. The AER could allow the TNSP to earn extra revenue of a value up to the specified costs of DM implementation. The potential for an increase in price by passing through costs to customers would be offset by the long-term benefits to all stakeholders of increased realisation of DM potential and the encouragement of greater network familiarity with DM.

Question 96. Is there a role for further objectives in the Rules given the single NEM objective? To what extent should the general objectives currently included in the Rules be removed, reduced or rationalised?

Demand management could, and should, be inserted as a core objective in Section 6.2.2 of the Rules. This would properly take into account COAG's and the Commonwealth's expressed interest in improving energy efficiency through demand side options, as discussed in Section 1.2. The investigation and implementation of non-network solutions where cost effective would be a perfect addition to the list of objectives. Given that such solutions can result in a more efficient system and reduced costs for consumers, this would fit in well with other objectives regarding "efficient investment" (such as a, b, d, e, f). It would particularly complement objective k concerning the "long-term interests of consumers".

5. Disclosure of information

The annual public disclosure of information on emerging network constraints is essential to the development of non-network responses to these constraints. Information presented both in tables and in map form is necessary to engage non-network providers. To encourage the uptake of cost-effective non-network alternatives to transmission augmentation, such information should be required of TNSPs. The AEMC should investigate the benefits of annual, public disclosure protocols on emerging network constraints.

There is an anomaly in the current situation concerning disclosure by TNSPs of financial performance. Under existing regulations (up to 1 July 2005), "The TNSPs regulated by the ACCC are required to provide certified annual statements containing details of their

[17] NERA, *Augmentation of Supply to the Western Area: Preliminary Cost Effectiveness Analysis*, May 2003, p 36
[18] Independent Pricing and Regulatory Tribunal of New South Wales, *Guidelines on the Application of the D-factor in the Tribunal's 2004 NSW Electricity Distribution Pricing Determination*, April 2005, p 1

financial performance."[19] However, Energy Australia, "... did not provide consent to disclose information, [so] its details were not included in this report. The ACCC notes that this is the second year that Energy Australia has not provided consent."[20] This means the public have not been fully informed of the financial performance of a TNSP and so stakeholders are being shut out of the decisions made by a TNSP. Considering the regulated monopoly status of the TNSPs and the billions of dollars of investments that consumers ultimately pay for, there should be a full requirement for disclosure by all TNSPs, and this disclosure should be sufficient to allow for transparency of their financial position for all stakeholders.

In relation to DM providers and embedded generators, it is similarly essential that the networks disclose planning information so these proponents can evaluate potential investment opportunities to provide non-network support as an alternative to augmentation.

Question 9. How significant are information asymmetry problems for electricity transmission regulation?

Disclosure of information is fundamental to transparency and certainty of decision making, and it relies not on quantity but quality. To date, lack of information has proved a significant barrier within the NEM, both in terms of accountability of the regulator and restriction of entry by competitors (such as DM providers and embedded generators). A transparent process will provide greater certainty for all stakeholders (regulator, TNSPs and consumers) as well as potential investors. TNSPs should also provide information on their expenditure on demand management, alongside opportunities they have investigated and the potential value of deferrals of augmentation.

A useful model here is the Disclosure Protocol from the NSW Demand Management Code of Practice[21]. The purpose of such a protocol is presented as:

> *To inform the market in a timely manner, regular public reports on the status of the network are required. A standardised Disclosure Protocol is intended to ensure that distributors provide all necessary information in a clear and consistent form, without wasting effort in providing unnecessary information.*[22]

The protocol includes features such as planning guidelines, for describing the basis for load forecasts and describing the system planning guidelines. It includes pro forma spreadsheets, requests for maps and summary table requests to assist with clarity of presentation and so there is some standardisation of the information lodged.

The Rules need to refer to guidelines for reporting developed by the AER, to refer to financial statements and applications for determinations.

These arguments also apply to:

[19] Australian Competition & Consumer Commission, *Transmission Network Service Providers Electricity Regulatory Report for 2003/04*, April 2005, p 1
[20] Ibid., p 1
[21] Department of Energy, Utilities and Sustainability, *Demand Management for Electricity Distributors – NSW Code of Practice,* September 2004; the Disclosure Protocol is on pp11-14
[22] Ibid., p 11

> *Question 10. What issues arise under the current building block approach in respect of information asymmetry?*
>
> *Question 11. To what extent would these be addressed by the adoption of an approach that relied on benchmarks to a greater extent?*

Question 101. Are there benefits in requiring the AER to issue an initial framework document for each transmission review setting out specific information requirements?

The AER should develop standardised reporting guidelines. This also applies to:

> *Question 112. Should the Rules set out high level qualitative principles in relation to the AER's information gathering powers, or should they seek to prescribe what information is to be provided, both routinely, and/or on an occasional basis?*

Question 102. Are there advantages in adopting an alternative process where the initial step of submitting an application is left to the TNSP?

No, for the reasons discussed above. It is usually more effective in terms of allocation of time (for a business) to follow an existing set of guidelines than develop an application from scratch. It also provides other stakeholders with a more consistent set of data, making the information more available for comparison and benchmarking.

Question 42. Are economic incentives necessary to ensure TNSPs provide the market with information about forecast constraints and reliability shortfalls?

Detailed and clear information about forecast constraints and reliability shortfalls is an essential tool to allow the DM and embedded generation market to respond appropriately and in good time to potential opportunities. It is essential that the timely publication of this information is made available to the public to allow non-network providers to offer support for constrained areas. If regulations ensuring this information are clear, TEC sees no need for further economic incentives since proper planning is beneficial to the whole industry.

Question 109. What information should the AER be obliged to include in a statement of the reasons for a determination?

If the AER expects full disclosure of pertinent details from the TNSPs then the principle should also work in reverse. There is no compelling argument not to disclose. Regulation must be consistent in both directions and apply both to the regulator and the regulated. If the regulator places information requirements on the transmission networks, then the regulator should be equally transparent in its decision making and notify the TNSP of the modelling it used. There is equally no compelling argument for inconsistency in methodology, thus modelling methods should be applied in similar situations. This information should also be publicly available. When the AER's decisions are clearly mapped out, with reasons for any decisions clearly stated, then stakeholders will be more reassured about the adequacy of the decision and more able to identify trends for future decisions (such as regarding investment).

The same arguments apply to:

Question 110. What are the arguments for and against a requirement in the Rules for the AER to provide details (either publicly or to the affected TNSP) of the modelling that underpins specific transmission determinations?

Question 111. Are there any perceived problems with the current Rules in relation to the provision of information, and if so, what are they?

Some of the problems have been referred to above for Question 9. In addition, there are problems with reporting on perceived potential constraints. All TNSPs (and in the future distribution and retail businesses) need to publicly provide clear information on areas facing constraints – or predicted to do so – in a reasonable timeframe (5, 10 and 15 years ahead) to allow DM providers to offer alternatives to augmentation. Such information should be required in order to encourage the uptake of cost-effective non-network alternatives to network augmentation and to ensure least-cost provision for consumers and an efficient NEM. Lack of quality information can inhibit new entrants to the market.

DEMAND MANAGEMENT CODE REVIEW WORKING GROUP

Demand Management for Electricity Distributors

NSW Code of Practice

May 2004

ESTABLISHED BY THE NSW DEPARTMENT OF ENERGY, UTILITIES AND SUSTAINABILITY
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Demand Management for Electricity Distributors

NSW Code of Practice

1. Purpose of Code

The purpose of the *Demand Management for Electricity Distributors NSW Code of Practice* (the Code) is to provide guidance to electricity distributors[1] in implementing the requirement in the NSW *Electricity Supply Act* 1995 to investigate and report on demand management strategies when it "would be reasonable to expect that it would be cost-effective to avoid or postpone the expansion [of a distribution system] by implementing such strategies".

2. Statutory Requirements

The *Electricity Supply Act* 1995 requires an electricity distributor operating in NSW to hold a licence. The licences are subject to conditions imposed by the *Act* and by the Minister for Energy and Utilities.

The *Act* requires that the Minister for Energy and Utilities impose a condition on each licensed electricity distributor to conduct investigations on the cost effectiveness of implementing demand management strategies that may permit distribution network augmentation work to be deferred or avoided.

Specifically, Schedule 2(6)(5) of the *Act* states:

> *(5) Without limitation, the Minister must impose the following conditions on each electricity distributor's licence:*
>
> *(a) a condition requiring the holder of the licence, before expanding its distribution system or the capacity of its distribution system, to 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 to would be reasonable to expect that it would be cost-effective to avoid or postpone the expansion by implementing such strategies,*
>
> *(b) a condition requiring the holder of the licence to prepare and publish annual reports in relation to the investigations carried out by it as referred to in paragraph (a).*

In accordance with the *Act*, the Minister has imposed licence condition 3.1 in all electricity distributors' licences. This condition substantially repeats the wording from the *Act*. The Code provides guidance on implementing the requirements in the *Act* and licence condition 3.1. The inaugural Code was recognised by the NSW Department of Energy, Utilities and Sustainability on 28 October 1999 with the subsequent revised Code recognised in May 2001.

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[11] In the *Electricity Supply Act* and in this Code, the term "distributor" is used. It has the same meaning as "distribution network service provider" (DNSP), the term used in the National Electricity Code.

The requirements in the *Act* and the Code operate in parallel with the National Electricity Code and have complementary objectives. In particular, in the National Electricity Code (as it stands at the time of writing), Clause 6.10.3 for distribution networks (and similarly Clause 6.2.3(d)(2) for transmission networks) require that:

> *(e) The regulatory regime … must also have regard to the need to:*
>
> > *(2) create an environment in which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration.*

Further, Clause 5.6.2 of the National Electricity Code (augmentation) requires that, among other things:

> *(f) Within the time for corrective action notified in Clause 5.6.2(e) the relevant Distribution Network Service Provider must consult with affected Code Participants and interested parties on the possible options, including but not limited to demand side options, generation options and market network services provider options to address the projected limitations of the relevant distribution system except that a Network Service Provider does not need to consult on a network option which would be a new small network asset.*
>
> *(g) Each Distribution Network Service Provider must carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the regulatory test, while meeting the technical requirements of Schedule 5.1 of the Code and where the Network Service Provider is required by Clause 5.6.2(f) to consult on the option this analysis and allocation must form part of, the consultation on that option.*
>
> *(h) Following conclusion of the process outlined in clauses 5.6.2(f) and (g), the Distribution Network Service Provider must prepare a report that is to be made available to affected Code Participants and interested parties which:*
>
> > *(1) includes assessment of all identified options;*
> >
> > *(2) includes details of the Distribution Network Service Provider's preferred proposal and details of:*
> >
> > > *(A) its economic cost effectiveness analysis in accordance with Clause 5.6.2(g)(1); and*
> > >
> > > *(B) both its determination in accordance with Clause 5.6.2(g)(2) and its consultations conducted for the purposes of that determination.*
> >
> > *(3) summarises the submissions from the consultations; and*
> >
> > *(4) recommends the action to be taken.*

As guidance on implementing the requirements in the *Act* and licence conditions, the Code does not aim to specifically address the requirements of the complementary objectives in the National Electricity Code. Understanding of these requirements is best sought directly from the current version of the National Electricity Code.

3. Scope of Code

The scope of this Code is to provide guidance to distributors on how to meet their licence obligations through the market-based development of options for electricity system support (including demand management, embedded generation and storage options). Also covered is the evaluation process of all feasible options to ensure consistency and transparency.

This Code recognises that the focus should not just be on the network, but rather on the delivery of end-user energy services by means of the electricity system as a whole. Constraints that arise within the distribution network can be addressed by changes in customer behaviour, by changes in equipment used by customers or by installation of small-scale generation at a local level, as well as by enhancement of the distribution network.

These options could be devised and implemented by customers or by distributors. The market-based procedure in the Code is intended to ensure that all supply and demand side options developed by customers or third parties and by the distributor itself can be developed and evaluated at the same time and in the same manner as network augmentation, including the use of a competitive process.

Within this overall framework the Code’s focus is specifically on distribution network expansion issues while responsibility for Greenhouse gas abatement is placed principally with retailers. The cost-effective deferral or avoidance of generation expansion is left to market forces under incentives from the national electricity pool arrangements.

As guidance to the NSW electricity distributors this Code’s objectives are for transparency in information provision and equal treatment in processes and evaluation in “circumstances in which it would be reasonable to expect that it would be cost-effective to avoid or postpone the expansion of the network by the implementation of such (demand management) strategies”. As such the Code forms one part of an overall regulatory framework supporting demand management and energy efficiency in the electricity industry, other key elements being:

- economic regulation for electricity pricing and cost recovery for distribution network projects administered by the Independent Pricing and Regulatory Tribunal (IPART)
- economic regulation for electricity pricing and cost recovery for transmission network projects administered by the Australian Competition and Consumer Commission (ACCC)
- price signals and information on opportunities for generation within the national electricity market
- energy efficiency ratings of houses and appliances
- the Commonwealth Government’s Mandatory Renewable Energy Target
- NSW Government's Greenhouse Gas Abatement Scheme administered by IPART.

Demand management activities undertaken by proponents may be eligible for payments either as an up-front payment or on a periodical basis from electricity distribution network operators. In addition proponents may also be eligible for payments negotiated for transmission or generation benefits in return for demand reductions, such arrangements are outside the scope of this Code, but not precluded by it.

In meeting these statutory obligations relating to demand management, the Code covers the objectives to:

- publish information that makes transparent the underlying assumptions and decision making process relating to investments that expand their distribution networks
- publish detailed information regarding the need for network expansion in a way that enables interested parties to identify likely locations of forthcoming constraint
- use a formal process to determine whether demand management investigations are warranted for identified emerging constraints, and publish the results
- carry out demand management investigations that provide opportunities for market participation
- analyse demand management and network expansion options on an equal basis according to the published methodology and assumptions and publish the result of those determinations
- implement demand management options where they are determined to be cost-effective
- prepare and publish reports on these activities annually.

4. Definitions

The term "demand management" covers a range of actions taken by generators, networks, retailers, other energy service intermediaries and end-users to alter the level or pattern of consumption of energy, the source of energy, or use of the distribution network.

This Code is specifically directed towards electricity distributors and therefore demand management activities to be reported shall encompass, but not be restricted to the following broad classifications:

- **energy efficiency**, which includes activities that reduce the amount of energy consumed in meeting end-user needs, such as lighting, heating/cooling and power. Examples of such activities include introducing higher efficiency equipment or appliances, improving the management of a process or facility, or reducing waste through actions such as installation of thermal insulation or waste heat capture.

- **load management**, which describes activities designed to reduce peak load on the electricity system as a whole or in particular parts of the system. Examples would include but not be restricted to customer power factor correction, curtailable or interruptible load agreements, off-peak hot water control systems, fuel substitution, time of use tariffs, hydrogen storage systems, water storage systems to reduce pump sizes, other energy storage systems, cycling of air-conditioning and smart-house systems.

  It is recognised that some activities may also reduce the peak demand on the generation sector; however, this Code focuses on demand on the distribution network.

- **distributed generation** (also known as embedded generation), which refers to electricity generation that is connected within a customer's or distributor's network rather than within the transmission network. Distributed generators are sometimes located close to electricity loads or may be linked to industrial processes eg cogeneration. Distributed generation can also refer to generation that is not permanently connected to the network, and so can include stand-alone systems that are separate from the network.

Distributed generation would normally only be considered to provide a demand management function where it can be relied upon by the distributor to be available when required, thereby enabling distributors to postpone or avoid network upgrades.

Examples would include systems that have inherently high availability such as stand by generators or systems with adequate energy storage capacity. Alternatively generators which can be demonstrated to provide capacity coincident with system peaks may also qualify.

Distributor acceptance of a higher risk of supply interruptions is not considered a valid demand management program.

The connection of distributed generators to the network shall be in accordance with the standard conditions of the distribution network service provider. However, the distributor shall be mindful of the general community benefits that may accrue from such generators and work with the proponent to achieve the connection at least cost to the proponent where possible.

Where a capital contribution for connection is necessary, such work would normally be classified as contestable work and may be undertaken by appropriately qualified accredited service providers.

5. Framework: Market-Based Electricity System Development

Background

There are two key opportunities for distributors to use market mechanisms in electricity system development:

- in improving information gathering and identification of options
- in testing for and selecting the best option for network development.

Supply-side or demand-side options developed and implemented by the distributors are likely to continue to provide the bulk of additional system support for the foreseeable future. However, to ensure competitive neutrality, third party proponents should have comparable access to the information required to develop alternative proposals. Third parties should also be able to have confidence that their proposals will be given due consideration in the evaluation of proposals.

The procedure requires several new elements:

- a process for informing the market by disclosing appropriate information about the current and future state of the electricity supply system (see Section 6 – Disclosure Protocol)
- a process for fully and consistently specifying the constraint in the electricity supply system (see Section 7 – Specification Protocol)
- a process for fairly and consistently evaluating proposals to overcome this constraint (see Section 8 – Evaluation Protocol).

While this procedure demands greater transparency and consistency of approach from the distributors in developing their networks, it also clarifies the requirements on distributors and should thereby streamline the development process and provide greater certainty over the recovery of investment.

Explanation of Flowchart

The procedure for electricity system development is summarised in Figure 1 below.

Figure 1 comprises three columns. The shaded boxes in the left-hand column summarise the generic steps to be undertaken. The flow chart in the central column details the required procedure. The group of three boxes on the right-hand side refer to the protocols that inform the procedure at each key step. The two boxes beneath the protocols identify the regulators to which the distributors report their activities in relation to procuring system support, including demand management.

Note that the procedure flowchart starts with two parallel activities:

- the distributor publishes an annual Electricity System Development Review (ESDR)
- the distributor develops generic system support options.

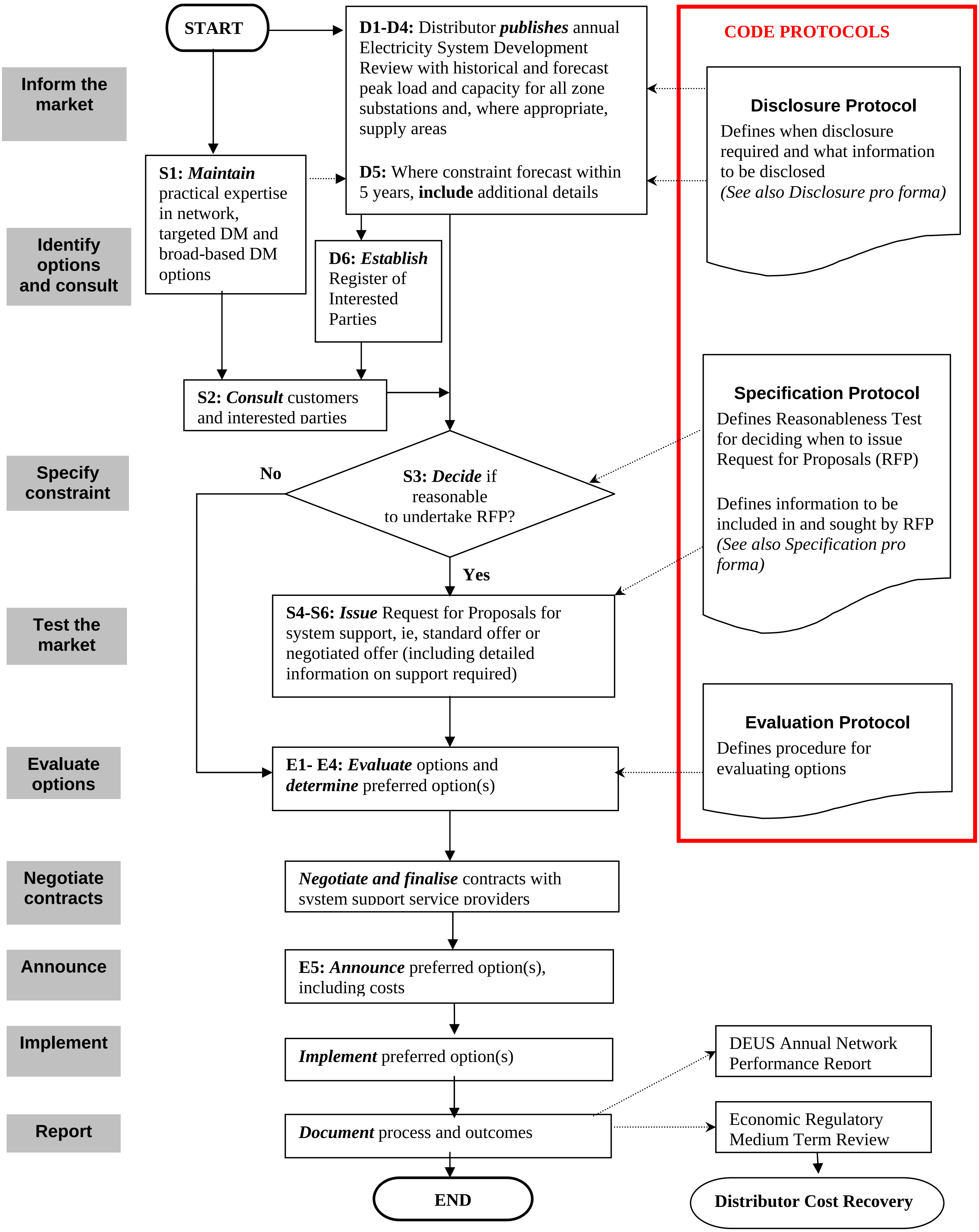
The distributor is required to initiate both these activities. These two activities merge in two subsequent activities:

- disclosure of information relating to specific forecast constraints
- consultation with customers and other interested parties in relation to specific forecast constraint.

The processes of disclosure and consultation on the one hand and developing generic system support options on the other are linked in that each informs the other, particularly in relation to identifying specific system support options in specific areas of constraint.

The three protocols – disclosure, specification and evaluation – are detailed in Sections 6, 7 and 8 respectively. An illustrative example of the availability and payment schedules for a standard electricity system support contract appear in the Appendices to the Code.

Figure 1: Electricity System Development Procedure for Distributors



6. Electricity System Information Disclosure

Background

To inform the market in a timely manner, regular public reports on the status of the network are required. A standardised Disclosure Protocol is intended to ensure that distributors provide all necessary information in a clear and consistent form, without wasting effort in providing unnecessary information.

The Disclosure Protocol requires two levels of information to be disclosed annually:

- a low level of detail across the whole system to provide an indication of where constraints are, and are not, likely to emerge in the foreseeable future
- a medium level of detail for parts of the system where a constraint is forecast within five years to allow customers and third parties to consider whether they may be able to assist in addressing the constraint.

A higher level of detail is required when action is being taken to address specific constraints. This is detailed in the Specification Protocol.

The Disclosure Protocol requires the distributor to publish a description of the planning guidelines used to decide when there is a need for new system support. This may include the minimum customer service or reliability standards where this forms part of the planning criteria.

The Disclosure Protocol also requires the establishment of a Register of Interested Parties for customers, service providers and others who wish to be kept informed of developments relating to specific anticipated system constraints.

Disclosure Protocol

The following information is to be disclosed by the distributor in an annual Electricity System Development Review (ESDR).

D1. Frequency of disclosure

To be published by 31 May each year.
(The same information will be provided to NEMMCO for compiling the Annual Statement of Opportunities.)

D2. Scale for disclosure

a. Information to be disclosed for all subtransmission and zone substations (ie $\geq$ 33 kV primary feed).
b. Information should also be disclosed for lower voltage network assets where significant network support expenditure is anticipated or where the distributor considers it desirable to provide a more complete picture of network constraints and network development.
c. In addition, where applicable, information may be provided for aggregated supply areas where there are multiple zone substations supplying or capable of supplying a given area or for other major constraints (such as transmission feeder limitations) which cannot be adequately described by the zone substation data alone.

D3. Planning guidelines

a. Description of the basis for formulating load forecasts.
b. Description of system planning guidelines for determining when new system support is deemed to be required.

Demand management should not cause a deterioration in the prevailing adequacy, security or power quality of any customer, except with the prior agreement of the distributor and the customer.

D4. Information to be disclosed for all zone substations (and multiple substations supply regions where appropriate)

(See Disclosure pro forma spreadsheet.)

a. zone substation name/ID:
b. site/address: locality: postcode:

The following information is desirable and should be provided where available.

c. zone substations capable of sharing load (name/ID):

For the following items**,** actual data for each of the past 10 years should be provided (if full 10 years of data is unavailable, at least five years of data should be provided) and forecast data for next five years should be provided where available:

d. total capacity
e. firm delivery capacity (Summer and Winter - allowing for reliability standard and primary feed capacity)
f. peak load (Summer and Winter)
g. is a constraint forecast within five years? (Yes/No)

h. If yes, brief description of trends/factors driving constraint.

The ESDR shall include a summary table of demand and rating conditions for all zone substations. An example is included as Appendix 2. Distributors should also present the information in a map identifying the magnitude of the constraint and network expenditure. Examples of the maps are included as Appendix 3.

D5. Information disclosure for zone substations with forecast system constraint within five years

Forecast data for next five years:

a. total capacity, firm delivery capacity and peak load (as in D4 above)
b. extent of overload (peak load > firm capacity; MVA)
c. frequency of overloads (days pa where peak load > firm capacity)
d. length of overloads (hours pa where peak load > firm capacity)
e. power factor at time of peak load.

Other information:

f. customer service/reliability targets for supply to customers served from that substation for past five years and forecast for the next five years (if available)
g. specify security standard (if other than that described in D3 above)
h. load trace/data for (current actual) peak day
i. annual load duration curve/data
j. nature of load at time of peak/constraint – proportion of industrial, residential, commercial etc, size of specific key loads if known (eg domestic space heating, commercial air conditioning, etc) and principal driver/s for growth where available
k. brief description of possible system support options for overcoming the constraint and their estimated total cost and/or annualised cost
l. forecast date that electricity system support investment decisions must be made
m. statement of whether distributor plans to issue a Request for Proposals (RFP) for electricity system support? If yes, expected date
n. if currently unknown whether a Request for Proposals will be issued, expected date that decision on issuing a formal RFP will be made
o. outline of how distributor intends to inform and test the market (eg direct consultation with major customers, pilot demand management initiatives, simple RFP alone, standard or negotiated offerings to purchase given volume of system support at a specified price, residential programs, use of energy service companies, demand management aggregators and market intermediaries, etc). See Section 9 for more details on standard and negotiated offers.

D6. Register of Interested Parties

For each supply constraint forecast to occur within five years, a Register of Interested Parties will be established. Any party requesting to be added to this Register will be kept informed of developments relating to this constraint. The distributor will consider any information submitted by interested parties when applying the Reasonableness Test when deciding whether to issue a Request for Proposals for electricity system support (see Section 7 – Specification Protocol). Names and information on the Register will be public including web addresses unless specifically requested otherwise by the interested party.

Disclosure Protocol

System Development Review Disclosure proforma

Zone Substation Name/ID:
Site/Address:
Locality: **Postcode:**
Zone Substations sharing load:

		Winter				**Summer**		
		Total Capacity	**Firm Capacity***	**Peak Load**		**Total Capacity**	**Firm Capacity***	**Peak Load**
	Year	MVA	MVA	MVA		MVA	MVA	MVA
Actual	1990							
	1991							
	1992							
	1993							
	1994							
	1995							
	1996							
	1997							
	1998							
	1999							
	2000							
Projected	2001							
	2002							
	2003							
	2004							
	2005							
	2006							
	2007							
	2008							
	2009							
	2010							
	2011							

7. System Constraint Specification

Background

For proponents of network and non-network options to offer relevant proposals, it is essential that the system constraint be fully and accurately specified. To this end, a standard Specification Protocol is required. This Protocol also describes the process through which alternative options can be invited and proposed in a manner that allows direct comparison with each other and with options developed by the distributor.

The Specification Protocol requires distributors to consult with customers (including new load nominations where applicable/appropriate) and interested parties in relation to system constraints and options to address them. Distributors should maintain an adequate analytical capacity to develop and evaluate a range of system support options. This capacity may include both staff resources and suitably qualified demand management service providers.

Distributors may, utilising their normal procurement processes, engage demand management service provider/s to:

- investigate the potential for demand-reducing initiatives in customers' premises
- negotiate with customers to determine their level of interest to participate
- prepare a report detailing the potential for demand management in accordance with the distributor's requirements
- conduct other tasks as stipulated by the distributor.

The demand management service provider undertaking the investigation will need to meet the requirements of the distributor in terms of:

- number of buildings audited
- types of equipment/processes audited
- details of the initiative identified in terms of technology, total implementation cost, total customer benefits, payback periods and other relevant details
- timeframe for completion
- any other requirements stipulated by the distributor.

The demand management service provider may receive a payment for this service on submission of a satisfactory report if requested as part of an RFP or have access to the standard offer or negotiated offer for demand reduction for that constraint area. The payment for investigation may be based on the level of detail of the investigation, the number of buildings to be audited and the systems/equipment to be audited. The standard or negotiated offer payment will be based on the deferred capital expenditure.

The distributor may recover any prudent expenditure for demand management services as provided for in the economic regulator's distribution network pricing determination.

Any such work undertaken by contractors should neither advantage nor disadvantage demand management service providers in relation to any subsequent standard or negotiated offer.

The Specification Protocol defines a Reasonableness Test which the distributor should apply in deciding whether to issue a formal Request for Proposals. in relation to each constraint. This test states that the where the total annualised cost of addressing the system constraint is likely to be greater than $200,000 in a single year, then a RFP should normally be issued. Annualised cost includes the annual operating cost plus the total annual net cost of servicing capital expenditure, including financing charges and capital depreciation. RFPs may also be issued for smaller and less costly constraints.

The Specification Protocol defines the information that should be included in the RFP, where a distributor decides to issue one. In addition to an update of information already released in accordance with part D5 of the Disclosure Protocol, the distributor should specify the level and timing of system support required (see Specification pro forma).

The required content of proposals in response to a Request for Proposals is outlined in part S5 of the Specification Protocol (see also Schedules 1, 2, 3 and 4 in Appendix 1 to this Code).

As part of a public RFP process, distributors will call for demand reduction within a particular location or supply area. As part of the RFP, the contract with the distributor may be staged with interim progress payments to allow either the distributor or the proponent to withdraw at some stage into the delivery process if the contract is subsequently not expected to achieve the contracted outcomes.

The level of incentive payment is to be negotiated between the distributor and the demand management service provider (see Section 9 – Payment Level for Standard Offer for details).

Specification Protocol

S1. Develop and maintain expertise on system support options

The distributor will develop and maintain an adequate practical and analytical capacity to identify and evaluate a broad range of system support options including both demand management and network augmentation. The distributor will draw on this expertise to:

a. develop generic network options and demand management options to address specific system constraints as they arise, and more broadly-focussed demand management options where strategic, long-term load reduction is appropriate
b. estimate the cost of overcoming constraints (see D5(k) in Disclosure Protocol)
c. assist in consultation with customers and interested parties
d. ensure that demand management options are given consideration equal to that accorded to network enhancement options.

S2. Consult customers and other interested parties

Where a zone substation is facing a constraint within five years, the distributor will consult with (existing and new) customers and interested parties to raise awareness of any forthcoming system constraints and to explore the potential for customer and interested party involvement in providing electricity system support options including demand management.

As part of this process distributors may, where appropriate, engage suitably qualified demand service providers to assist with the investigation of demand management opportunities and to negotiate with customers to determine their interest in participating.

S3. Reasonableness Test

a. Where a zone substation is facing a constraint within five years, the distributor will decide whether it is reasonable to issue a formal Request for Proposals (RFP) or other direct approach to the market for electricity system support.

b. Unless previously published in the annual Electricity System Development Review, the distributor shall advise registered interested parties of the outcome of its application of the Reasonableness Test at least nine months prior to the forecast date that system support investment decisions must be made.

c. A RFP will normally be issued where the system constraint meets the following criteria:
   - the expected overloading is sufficient to require investment in system support to meet the distributor's reliability planning guidelines (see D3 above)
   - the estimated forecast annualised cost of adequate system support is at least $200,000 for at least one year.
     (Annualised cost equals annual fixed and operating costs plus financing costs plus depreciation.)

d. A RFP may be issued for constraints of smaller size and cost than this subject to consideration of the following matters:
   - any relevant information or proposals submitted by interested parties
   - any relevant information gathered in steps S1 and S2 above
   - the significance of the constraint or of possible system support options to the local or wider community.

e. Where it does not issue a formal RFP or other direct approaches to the market to overcome an anticipated constraint, the distributor should explain why and demonstrate how it has undertaken fair and reasonable steps to allow non-network based system support providers to develop and to service the market.

S4. Issuing the Request for Proposals

A Request for Proposals (RFP) will invite registered parties, customers and other proponents to offer system support to overcome a specified system constraint. The RFP may specify an indicative, fixed or maximum price that will be paid for system support, or may leave bid price to be determined by the proponents. To support the RFP, the distributor may also use other mechanisms such as those described in D5(o) above. Other requirements include:

- the distributor shall advise all registered interested parties of the release of the RFP
- the distributor shall publicly advertise the release of the RFP
- the RFP will be issues at least eight months prior to the forecast date that system support investment decisions must be made
- the RFP will allow at least eight weeks for submission of proposals.

The Request for Proposals shall include the following information:

a. the level and timing of electricity system support required. (see Specification pro forma)
b. up-to-date information relating to items (a) to (m) in section D5 of the Disclosure Protocol
c. results/report from investigation and negotiation with customers, including interested customers contact (with consent), where applicable
d. load trace/data for the largest existing commercial / industrial customers where applicable and where customer consent is provided
e. expected MVA contribution by new commercial/industrial/residential load nominations per year where applicable
f. all relevant assumptions to be used in the evaluation of proposals/options (see also E3 below).

Prior to an RFP being issued the distributor may provide a standard or negotiated offer of payment for demand reduction. Standard or negotiated offers may cover longer term constraint areas, ie, between five to 10 years ahead, (see Section 9 – Demand Management Procurement for more details on standard or negotiated offers), as well as shorter term constraint areas which may also be covered by an RFP.

S5. Content of proposals

Proposals may involve an individual project or an aggregation of a number of projects to cover a wider area of network constraints, refer section D4 and D2. (For evaluation purposes, the distributor may also aggregate proposals – see E4 in Evaluation Protocol).

Proposals should include the following information:

a) the name, address and contact details of the party making the proposal
b) the name, address and contact details of the party responsible for the system support option (if different to above)
c) a brief explanation of the relevance of the proposal
d) the size, type and location of load/s that can be reduced, shifted, substituted or interrupted
e) the size, type and location of generators that can be utilised if required
f) the type and location of action or technology proposed to reduce peak demand/ provide electricity system support

g) the time required to implement these measures, and any period of notice required before loads can be interrupted or generators started
h) an estimate of the expected reliability expressed in terms of the availability factor of the option for that portion of the required period for which the option is offered (i.e. the probability that the option will be available if called upon)
i) other relevant information, including environmental impacts
j) the level and availability of electricity system support from this proposal (see System Support Contract Schedule 1 in Appendix 1*)*
k) the level of initial payment required ($ and/ or $/kVA)
l) the level of availability payment required ($/MVAh; see System Support Contract Schedule 2 in Appendix 1)
m) the level of dispatch payment required ($/MVAh; see System Support Contract Schedule 3 in Appendix 1)
n) the level of compensation payment payable to the distributor in the event of failure to provide system electricity system support when required ($/MVAh; see System Support Contract Schedule 4 in Appendix 1)

S6. Confirmation of conformance

A proponent may submit a draft proposal to the distributor prior to the due date for submission in order to confirm that the draft proposal conforms to the RFP. Where such confirmation is sought, the distributor will respond as soon as possible.

Specification Protocol

Constraint Specification pro forma.
(System Support Required)

Year:

REVISED	Period no.	Example		1	1	2	2	add additional periods as required								
		w'day	w'end	w'day	w'end	w'day	w'end									
	Date from	1-Dec-03	1-Dec-03													
	Date to	29-Feb-04	29-Feb-04													
	time	**Capacity req'd (MVA)**														
	0:00															
	1:00															
	2:00															
	3:00															
	4:00															
	5:00															
	6:00															
	7:00															
	8:00															
	9:00															
	10:00	1														
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	13:00	3														
	14:00	3														
	15:00	3														
	16:00	3														
	17:00	2														
	18:00	1														
	19:00															
	20:00															
	21:00															
	22:00															
	23:00															
Maximum required eq. Cont operation (hours)		8														
Notification time (hours)		24														

8. System Support Option Evaluation

Background

For disparate network enhancement and other system support options to be equitably assessed a standard Evaluation Protocol is required.

The purpose of the Evaluation Protocol is to ensure that all network enhancement and other system support options and proposals are given fair consideration. This evaluation should include all relevant costs and benefits.

The Evaluation Protocol indicates that all conforming options should be evaluated and ranked on the basis of total annualised cost of providing the system support. This cost should be adjusted to account for the relative risk profile of options.

The Evaluation Protocol requires distributors to publicly announce the recommended option/s resulting from the evaluation and the annualised cost to the distributor of the recommended option/s.

Evaluation Protocol

E1. Options to be evaluated
Where a RFP has been issued and/or where alternatives to a RFP under parts D5(o) and S3(e) are proposed, all conforming options shall be evaluated. Conforming options developed by the distributor will also be evaluated.

E2. Clarification of proposals
The distributor may seek clarification of details from the proponent of a proposed option provided this does not materially alter the proposal.

E3. Basis of evaluation
a. Options (and where necessary groups of options) will be evaluated and ranked on the basis of the total net annualised costs of system support incurred by the distributor, plus the cost or benefits of changes to transmission and distribution losses taking into account the future performance and flexibility of various options[2]. "Total net annualised costs incurred by the distributor" include all capital, fixed and operating costs of securing the specified level of system support.
b. System support is measured in terms of kVA of constrained peak capacity, $/kVA of constrained peak capacity and the period of constraint.
c. A 10-year period for evaluation is recommended (but a different period may be chosen provided a sound rationale is given).
d. Environmental and other external costs should be included in the evaluation wherever these reflect an existing or anticipated regulatory obligation of the distributor[3].
e. The relative intrinsic risk profile of specific options and technologies will be assessed in accordance with normal commercial practice.[4]

E4. Combination of proposals
In addition to evaluating proposals separately, the distributor may combine separate proposals for the purposes of evaluation where this may lead to a more desirable outcome than the separate proposal. Proponents should indicate on their proposal whether they wish to have their proposals considered in combination with other proposals.

E5. Public announcement of recommendation of evaluations
The recommendations of all the evaluations will be publicly announced. This announcement will include the total annualised cost to the distributor of the recommended option/s. All details of proposals including cost information will be treated as public information unless clearly noted otherwise in writing by the proponent. The announcement will be released no longer than eight weeks after the closing date for submissions.

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[2] If the market operates efficiently, this basis of evaluation should accord with the ACCC's Regulatory Test as stipulated by clause 5.6.2 of the National Electricity Code. "Net" costs of demand management projects already include the benefits to customers.

[3] For example, the ACCC Regulatory Test Note 3 in "Notes on the methodology to be used in the regulatory test to a proposed augmentation". Available from www.accc.gov.au/electric/regulatory_test_final.html.

[4] Perceived risk due to lack of experience or familiarity by NSW distributors with specific options and technologies can also be a major barrier to commercial acceptance of new approaches to system support.

9. Demand Management Procurement

Background

The processes for procuring network support through network options are well established. This section outlines recommended processes for procuring network support through demand management.

There are at least two types of procurement offers that may be made to providers of demand management for system support: negotiable offers and standard offers.

For negotiable offers, the distributor and the demand proponent or network customer negotiate a contract specifically designed for that particular project. Negotiable offers are more appropriate for larger-scale relatively complex demand management projects where the transaction costs and time associated with negotiating a unique contract are relatively insignificant.

Standard offers specify the conditions for the provision of demand in advance. Standard offers are usually made on fixed prices, take it or leave it, first come first served basis.

It is recognised that demand reduction can provide long term network benefits, not only when the system constraint occurs. This is because such demand reduction can reduce the need for future network augmentation under a wide range of plausible future scenarios. The essence of cost-effective network demand reduction is the postponement of a known capital expenditure and funding the demand reduction option from the avoided distribution costs. Standard offers may be targeted to shorter-term constraint areas or to capture demand reduction opportunities that provide longer-term distribution network benefits by delaying future less well defined network constraints.

The standard offer is a means of providing financial assistance for the implementation of demand management at the customer level based on certain criteria being met. This financial incentive may be recovered as provided for in the economic regulator’s distribution network pricing determination.

Demand management initiatives may reduce energy consumption on an ongoing basis thus affecting the distributor revenue stream. Distributor revenue arrangements should ensure that effects on revenue do not act as a disincentive to demand management.

A standard offer may be made in conjunction with, prior to, or in place of a negotiable offer being issued or a constraint area being identified. A subsequent negotiable offer or RFP may revise the standard offer as the details of the constraint and requirement to overcome the constraint are more definite.

It may be considered prudent for distributors to make such offers where the firm rating of the local distribution network will be exceeded anytime within the ten year forecast period. It is envisaged that a standard offer can be made during the early period of a constraint being identified and be re-evaluated and incorporate in an RFP in accordance with the timeframe as detailed in Section 7 - Issuing the Request for Proposals.

The distributor will ensure that all standards offers are made open and public.

Criteria for the Standard or Negotiated Offer

A demand management procurement offer (standard or negotiated offer) may be geographically targeted at a particular local constraint or provided to all customers of the distributor that install or adopt eligible demand management initiatives. The demand management initiative must meet the following criteria:

- the demand management initiative must deliver a network benefit that would not exist in the absence of the offer
- an entity that is capable of implementing or project managing its implementation (known as the project proponent) implements the initiative
- aggregation of demand reduction will be recognised by the distributor where a single entity that is capable of implementing/project managing its implementation (project proponent or demand management aggregator) implements the initiative
- the demand management initiative may be installed in both a retrofit application and in a new construction application, subject to distributor approval
- the demand management initiative must meet or exceed minimum equipment standards as set out by the appropriate Australian and international standards
- the demand management initiative and/or the network benefits it provides must be able to be measured and verified to the satisfaction of the distributor.

The project proponent must comply with the application process as set out by the distributor.

Payment Level for Standard Offer

As the objective of the standard offer is to achieve cost-effective reduction in peak demand, the level of standard payment should generally not exceed what is considered the benefits derived from implementing the initiative. For the purposes of this Code, distributors are only expected to offer payments up to the value of the distribution network benefits. (While other costs and benefits may accrue in terms of distribution customer, transmission, generation and other environmental and societal impacts, these are not necessarily the responsibility of the distributor to coordinate or identify.)

This section outlines the principles a distributor may use to determine:
- the overall allocation of funds for implementing a certain demand management program
- the value of demand management in terms of $/kVA of permanent demand reduction or $/kVAhr of temporary demand reduction.

The principles are based on comparing a network augmentation option (build option) and a deferral option.

The analysis of total costs for both the build and deferral options should be performed using standard accounting principles, such as:
- time value of money (a consistent time frame ie 20 years)
- depreciation
- effects of residual value
- effects of tax
- average operating and maintenance costs
- applied weighted average cost of capital.

The value of the deferral option should be based on a one-year deferral period using the expected annual demand growth on the network[5]. The difference between the cost of the build option and the deferral option represents the avoided distribution cost, which effectively is the amount/budget available for implementing demand management to achieve one year of network augmentation deferral. This amount/budget may be divided by the expected annual demand growth on the network to determine the maximum $/kVA per annum (value of demand reduction) figure. This may then provide the basis for determining a $/kVAhr incentive payment figure.

For the purposes of this analysis revenues for both options are assumed to be equal. Any differences in revenue for the two options, in practice, should be factored into the financial evaluation and be clearly identified.

This total budget may be split up using several different methodologies to determine the $/kVA or $/kVAhr per annum incentive payment figure. Two possible methods include:

- dividing the total dollar figure by the kVA demand reduction required to determine an average $/kVA incentive payment figure (average value). RFPs are more suited to the publication of the average value for demand management
- going to the market and seeing what can be purchased at different prices. If lower cost demand reduction can be purchased the remaining budget may be used to provide a higher incentive $/kVA figure to implement the higher cost demand management initiatives.

A simple example of determining the $/kVA per annum and $/kVAhr incentive payment is provided.

Example

Assumption

a. Total amount/budget available for DM (avoided distribution cost): (From the difference in the build case and the deferral case)	$200,000
b. Demand reduction required for a one-year deferral:	2,000 kVA
c. Value of deferral: (=a/b) (Permanent reduction incentive payment)	$100 / kVA pa
d. Expected hours of demand reduction required in the first year[6]:	100 hours

A distributor receives two demand management proposals in response to a standard offer: 1,200 kVA comes from permanent (kVA) demand reduction, eg energy efficiency programs and 800 kVA comes from temporary (kVAhr) load shedding eg interruptible contract.

Calculation

Incentive payment for permanent demand reduction:

$100 / kVA pa	x	1,200kVA	x	1 year deferral	=	$120,000

Incentive payment for temporary demand reduction:

$100 / kVA pa	/	100hr	=	$1.00 / kVAhr		
$1.00 / kVAhr	x	800kVA	x	100hr	=	$80,000 (for one year deferral)

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[5] Distributors may choose to provide additional cases for longer periods of deferral, particularly where demand growth is not even, ie, large spot loads cause a jump in demand.

[6] The estimated total hours of reduction will increase in a non-linear fashion even though the demand may grow linearly. Therefore, the hours of overload needs to be averaged with future years overload levels.

10. Reporting

Regulations under the Electricity Supply Act

The *Electricity Supply (Safety and Network Management) Regulation* 2002 requires, amongst other things, that network operators lodge certain plans with the Department of Energy, Utilities and Sustainability including a network management plan. Operators must measure performance against these plans and publish performance reports annually[7].

Each year the Department of Energy, Utilities and Sustainability issues an *Electricity Network Performance Report Outline* stipulating the information required to be provided by network operators. This Outline includes reporting requirements for demand management activities and investigations.

Licence Conditions

NSW distributors also have Ministerially-imposed licence conditions which require licence holders to carry out investigations as to whether it would be cost-effective to implement demand management strategies and to prepare and publish annual reports in relation to these investigations. The Minister may also issue guidelines to be followed in relation to these investigations[8].

The Minister has issued a *Guidelines and Requirements Policy for Electricity Distribution Network Service Providers and Retail Suppliers*[9]. This document requires distributor licence holders to include in its Licence Condition Compliance Annual Report to the IPART, a report on the investigations required to be carried out in relation to demand management strategies.

The above two reporting obligations are fulfilled with the preparation of a single annual Electricity Network Performance Report by 31 August each year (in accordance with the Outline issued by the Ministry) and the lodging of this report to both the Department of Energy, Utilities and Sustainability and to the IPART accompanying the annual licence compliance report.

The reporting requirements of this Code follow the market-based process and are separated into the distinct protocol segments. The need for reporting is twofold: it informs the market about opportunities for future development and it provides information to the economic regulator that ultimately determines whether the investment mix will be deemed prudent and therefore recoverable.

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[7] See clauses 5 and 16 of the *Electricity Supply (Safety and Network Management) Regulation* 2002.

[8] See Section 1 of *Schedule Listing Ministerially Imposed Licence Conditions for Distribution Network Service Providers,* issued 14 November 2003.

9 See clause 3.4.1 of *Guidelines and Requirements Policy for Electricity Distribution Network Service Providers and Retail Suppliers* released July 1997 and revised June 2001. Note this document is being reviewed by IPART/Department of Energy, Utilities and Sustainability.

Items to be reported are:

1. Electricity System Development Review (ESDR) issue date. If the ESDR was not issued, the distributor is to submit a plan for issuing the ESDR
2. a summary report of zone substations that are likely to reach a capacity constraint within the next five years (compiled from the ESDR disclosure pro forma)
3. detail the criteria used to determine the Reasonableness Test (refer to Section 7 – Specification Protocol)
4. document the results of the Reasonableness Test for all items listed in (2)
5. reference any details of Request for Proposals
6. if no RFP is to be issued, the alternative action taken and its rationale
7. define the basis for evaluating the proposal and option/s
8. list the results of the evaluations conducted, including assessment of cost/benefit
9. provide a summary report of areas investigated and programs implemented
10. report on other ongoing programs such as off-peak control of hot water and other end-use appliances.

The data to be reported as part of the summary report (item 9) may include:

- total number of demand management programs investigated including a summary description of each investigation
- total number of demand management programs implemented
- total cost of demand management strategies
- NPV of distributor operating expenditure saved
- NPV of distributor capital expenditure deferred.

The reporting format for each protocol will generally follow that listed in Tables 1, 2.1, 2.2 and 3. The reporting format for the summary of demand management activities will generally follow that listed in Table 4. The actual annual reporting requirements may change and will be determined by the Department of Energy, Utilities and Sustainability.

TABLE 1

Information to be reported under
Disclosure Protocol

ESDR issue date	Number of ZS/Area constrained within 5 years	Key drivers of System Constraint

TABLE 2.1

Information to be reported under
Specification Protocol

ZS/Area constrained within 5 years	Results of the Reasonableness Test	Was a RFP issued?	Number of conforming proposals received	If no RFP issued, action taken and rationale

TABLE 2.2

Information to be reported under
Specification Protocol Criteria

Criteria used in Reasonableness Test

TABLE 3

Information to be reported under
Evaluation Protocol

ZS/Area constrained within 5 years	Options evaluated	Cost of each option	Preferred option mix	Number of years Capital Expenditure deferred

TABLE 4

Summary Report for Demand Management Activities

Total Number of demand management programs investigated	Total Number of demand management programs implemented	Total Cost of demand management strategies	NPV of distributor operating expenditure saved	NPV of distributor capital expenditure deferred

11. Review

A decision on the appropriate timing for the reviewing Code will be made by the Department of Energy, Utilities and Sustainability within two years of release of this Code. A working group will conduct the review with representatives of industry, stakeholders and regulators. Issues to be addressed will include, but will not be limited to:

- developments in signalling electricity system constraints, including network pricing
- distributors' and stakeholders' experiences with the market based approaches in this Code
- developments in the National Electricity Code process
- developments in the Demand Management Services Market.

Appendix 1: Indicative Schedules to a Standard System Support Contract

Schedule 1: Availability

Schedule 2: Initial and availability payments

Schedule 3: Dispatch payments

Schedule 4: Compensation payments for failure to deliver contracted capacity

Appendix 2: Sample Electricity System Development Review Summary Report

Appendix 3: Sample Maps for the Electricity System Development Review

Appendix: System Support Contract **Schedule No. 1- Availability**

Year:

	Period no.	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	10	10
	Period (Date)	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to
		wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend
	time	**Capacity Available (MVA)**				**Capacity Available (MVA)**				**Capacity Available (MVA)**				**Capacity Available (MVA)**				**Capacity Available (MVA)**			
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Continuous operation (hours)																					
Warning time (hours)																					

System Support Contract **Schedule No.** **2- Initial and availability payments**

Year:																				
Period no.	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	10	10
	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to
Period (Date)																				
	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend
time	**Avail'ity payment ($/MVAh)**				**Avail'ity payment ($/MVAh)**				**Avail'ity payment ($/MVAh)**				**Avail'ity payment ($/MVAh)**				**Avail'ity payment ($/MVAh)**			
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Initial payment ($/kVA)																				
Initial payment ($lump sum)																				

System Support Contract **Schedule No. 3- Dispatch payments**

Year:

	Period no.	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	10	10
	Period (Date)	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to
		wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend
	time	**Dispatch payment ($/MVAh)**				**Dispatch payment ($/MVAh)**				**Dispatch payment ($/MVAh)**				**Dispatch payment ($/MVAh)**				**Dispatch payment ($/MVAh)**			
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System Support Contract **Schedule No.** **4 - Compensation payments (for failure to deliver contracted capacity)**

Year:

	Period no.	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	10	10
	Period (Date)	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to
		wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend	wday	wend
	time	**Compensation pay't ($/MVAh)**				**Compensation pay't ($/MVAh)**				**Compensation pay't ($/MVAh)**				**Compensation pay't ($/MVAh)**				**Compensation pay't ($/MVAh)**			
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APPENDIX 2 SAMPLE ESR SUMMARY REPORT

SUMMARY OF FORECAST NETWORK SUPPORT REQUIRED

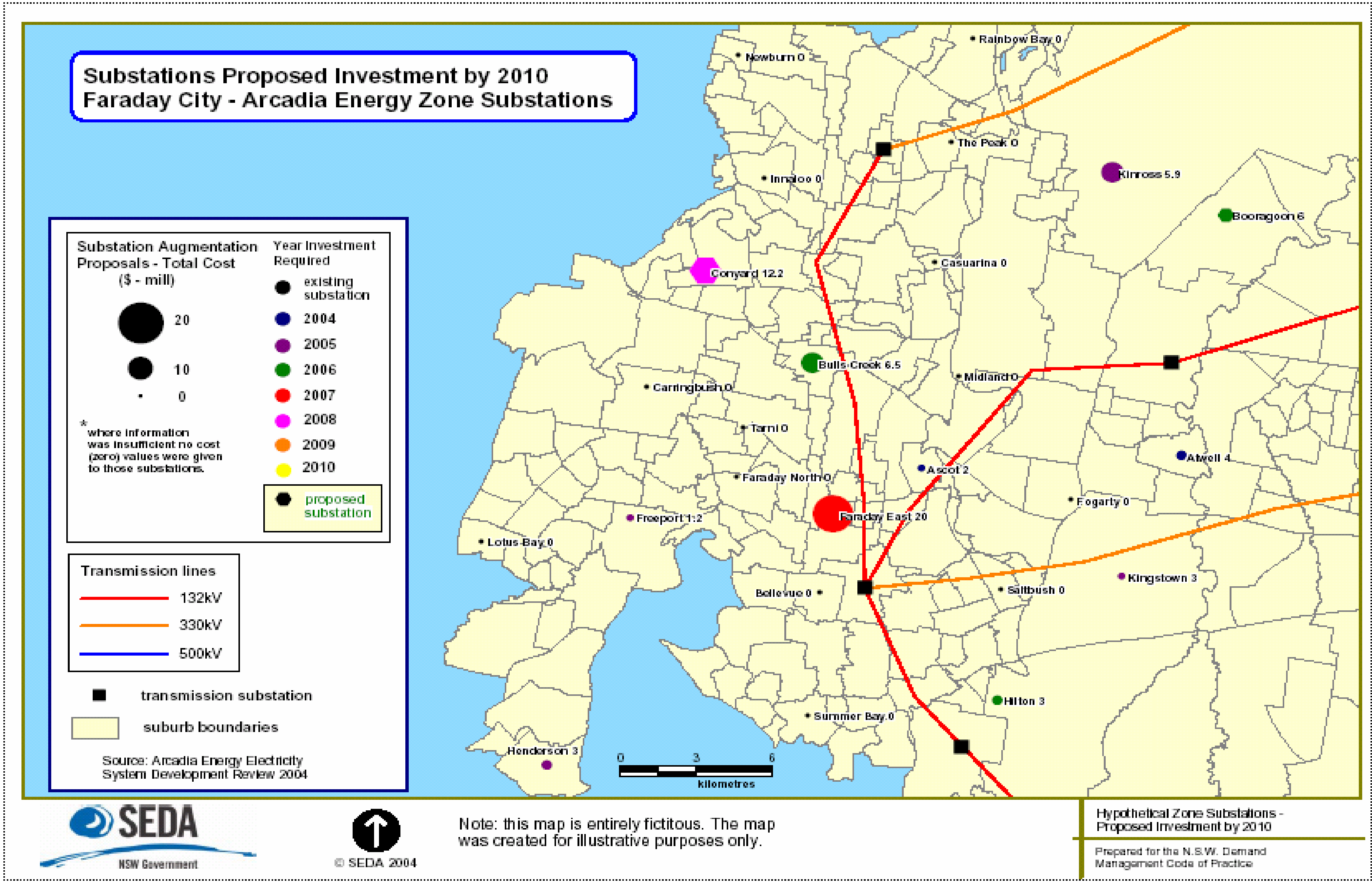
Current Year 2003

Forecast Year 2009

Zone Substation/STS	Total Capacity	Summer: Current Firm Rating	Summer: Forecast year peak load	Summer: Spare Firm Cap'y in Forecast Year	Winter: Current Firm Rating	Winter: Forecast year peak load	Winter: Spare Firm Cap'y in Forecast year	Possible Constraint Relief Projects	Project Ref Number	Cost	Year investment decision required	Season of Min Spare Firm Capacity	Spare Firm Cap'y in constraint season	Forecast Average Load Growth*
	MVA	MVA	MVA	MVA	MVA	MVA	MVA			Total ($m)	FY		MVA	MVA p.a.
MIDCOAST AREA														
Highview TS	440	270.00	200.0	70.0	270.0	190.0	80.0					Summer	70	11.0
Bulls Creek	30	20.00	30.0	-10.0	20.0	26.0	-6.0	Third 66kV feeder to Bulls Creek ZS	M06	6.5	2006	Summer	-10	3.5
Carringbush	35	25.00	33.0	-8.0	25.0	28.0	-3.0			0		Summer	-8	4.0
Conyard	36	24.00	23.0	1.0	24.0	24.0	0.0	Convert/rebuild Conyard for 132/11kV	M17	12.2	2008	Summer	0	1.0
Faraday North	60	45.00	45.0	0.0	45.0	41.0	4.0			0		Summer	0	-0.8
Innaloo	50	25.00	7.0	18.0	25.0	15.0	10.0			0		Winter	10	0.6
Kinross	30	15.00	23.0	-8.0	15.0	19.0	-4.0	Kinross ZS augment and land pruchase	M13	5.9	2005	Summer	-8	2.1
Newburn	40	20.00	14.0	6.0	20.0	17.0	3.0			0		Winter	3	0.6
Rainbow Bay	45	30.00	21.0	9.0	30.0	26.0	4.0			0		Winter	4	0.7
Tarni	35	25.00	19.0	6.0	25.0	13.0	12.0			0		Summer	6	1.2
The Peak	40	20.00	12.0	8.0	20.0	6.0	14.0			0		Summer	8	-0.5
EAST HILLS AREA														
Ranges TS	375	250.00	165.0	85.0	250.0	140.0	110.0					Summer	85	5.0
Ascot	40	20.00	28.0	-8.0	20.0	22.0	-2.0	Augment feeder 235	E02	2	2004	Summer	-8	1.4
Atwell	20	10.00	12.0	-2.0	10.0	10.0	0.0	Atwell 3rd transformer and 132 kV busb	E15	4	2004	Summer	-2	0.8
Booragoon	69	44.00	44.0	0.0	44.0	34.0	10.0	Rebuild feeder 168 to 132kV operation	E10	6	2006	Summer	0	1.2
Casuarina	50	25.00	5.0	20.0	25.0	0.0	25.0			0		Summer	20	-0.5
Fogarty	45	30.00	29.0	1.0	30.0	27.0	3.0			0		Summer	1	0.9
Kingstown	75	50.00	45.0	5.0	50.0	42.0	8.0	Rebuild feeder 102 to 66kV	E07	3	2005	Summer	5	1.3
Midland	50	25.00	22.0	3.0	25.0	18.0	7.0			0		Summer	3	-0.2
CENTRAL METRO AREA														
Voltaire TS	480	350.00	270.0	80.0	350.0	280.0	70.0					Winter	70	17.0
Bellevue	60	45.00	41.0	4.0	45.0	43.0	2.0			0		Summer	4	0.8
Faraday East	75	50.00	70.0	-20.0	50.0	65.0	-15.0	Rebuild Faraday East ZS	C12	20	2004	Summer	-20	4.2
Freeport	50	25.00	24.0	1.0	25.0	28.0	-3.0	Augment feeder 392 to higher rating	C08	1.2	2005	Winter	-3	2.3
Henderson	50	34.00	35.0	-1.0	34.0	38.0	-4.0	Henderson ZS 3rd transformer	C04	3	2005	Winter	-4	0.9
Hilton	70	35.00	45.0	-10.0	35.0	41.0	-6.0	Hilton ZS 3rd transformer	C16	3	2006	Summer	-10	2.8
Lotus Bay	60	45.00	32.0	13.0	45.0	37.0	8.0			0		Winter	8	1.2
Saltbush	50	25.00	21.0	4.0	25.0	15.0	10.0			0		Summer	4	2.3
Summer Bay	45	30.00	27.0	3.0	30.0	28.0	2.0			0		Winter	2	1.5

Note: Readers should refer to the individual zone substation tables and notes for more detailed information

Appendix 3 Sample Maps for the Electricity System Development Review



Appendix 3 Sample Maps for the Electricity System Development Review