

Demand Management for Electricity Distributors

NSW Code of Practice

September 2004



PREFACE

This Code of Practice was prepared by a working group comprising NSW electricity distribution network operators, the NSW electricity transmission network operator, the NSW economic regulator, electricity user representatives, environmental and consumer groups and a university representative, chaired by Integral Energy and facilitated by the Department of Energy, Utilities and Sustainability.

The Code of Practice is to provide guidance for electricity distribution network operators in meeting the requirement to carry out Demand Management activities in their operating licences.

DISCLAIMER

While due care has been exercised in the compilation of this Code of Practice, much of the content has been sourced externally from the Department of Energy, Utilities and Sustainability. Thus the Department of Energy, Utilities and Sustainability cannot accept responsibility for the content.

ENQUIRIES

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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 distributors¹ 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

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.

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.

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; and

- 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; and
- 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.

- **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.

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.

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:

- improving information gathering and identification of options; and
- 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); and
- 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); and
- the distributor develops generic system support options.

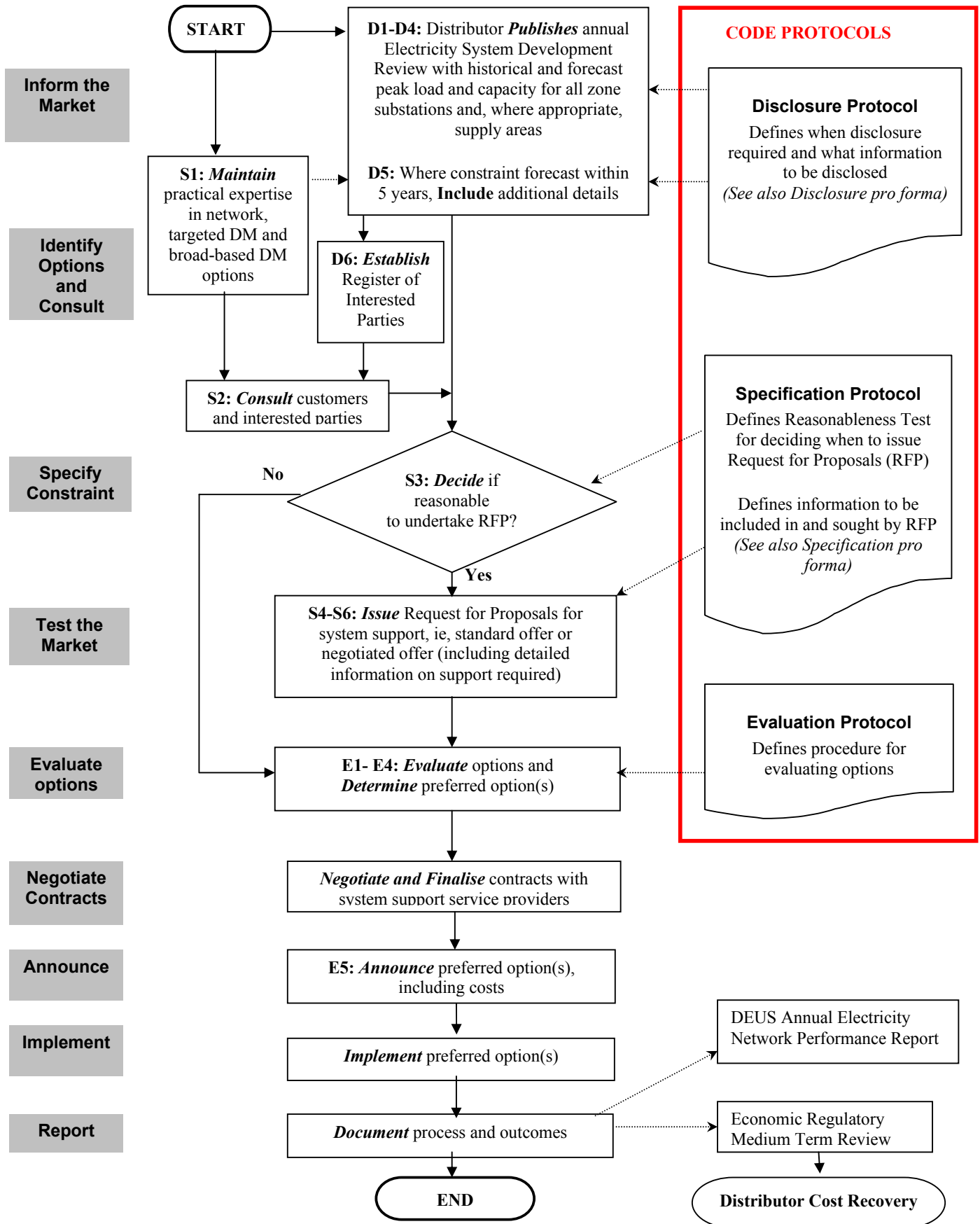
The distributor is required to initiate both these activities. These two activities merge in two subsequent activities:

- disclosure of information relating to specific forecast constraints; and
- consultation with customers and other interested parties in relation to a 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; and
- 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 sub transmission and zone substations (i.e. ≥ 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

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.

Figure 2: 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; and
- 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; and
- 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 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. An RFP 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 detail).

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; and
- 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 / new) customers and interested parties to raise awareness of forthcoming system constraints and to explore the potential for customer and interested party provision of 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); and
 - 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; and
 - 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 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 issued at least eight months prior to the forecast date that system support investment decisions must be made; and
- the RFP will allow at least eight weeks for submission of proposals.

The Request for Proposals shall include the following information:

- a. the level / timing of electricity system support required. (see Specification pro forma);
- b. up-to-date information on items 'a' to 'm' in section **D5.** of the Disclosure Protocol;
- c. results/report from investigation and negotiation with customers, including interested customers contacted (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; and

- 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, i.e., 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**); and
- 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

Figure 3: Specification Pro Forma

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	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											
11:00		2											
12:00		2											
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 options².
“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 distributor³.
- e. The relative intrinsic risk profile of specific options and technologies will be assessed in accordance with normal commercial practice.⁴

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.

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.

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.

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.

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; and
- 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 to be 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; and
- 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 i.e. 20 years);
- depreciation;
- effects of residual value;
- effects of tax;
- average operating and maintenance costs; and
- 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 network⁵. 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). An RFP is 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.

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.

Example:

An example of determining the \$/kVA per annum and \$/kVAhr incentive payment is:

Assumption

- a. Total amount/budget available for DM (avoided distribution cost): \$200,000
(From the difference in the build case and the deferral case)
- b. Demand reduction required for a one-year deferral: 2,000 kVA
- c. Value of deferral: (=a/b) \$100 / kVA pa
(Permanent reduction incentive payment)
- d. Expected hours of demand reduction required in the first year⁶: 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:

$$\$100 / \text{kVA pa} \times 1,200\text{kVA} \times 1 \text{ year deferral} = \$120,000$$

Incentive payment for temporary demand reduction:

$$\begin{aligned} \$100 / \text{kVA pa} & / 100\text{hr} = \$1.00 / \text{kVAhr} \\ \$1.00 / \text{kVAhr} & \times 800\text{kVA} \times 100\text{hr} = \$80,000 \text{ (for one year deferral)} \end{aligned}$$

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 annually⁷.

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

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.

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

these investigations. The Minister may also issue guidelines to be followed in relation to these investigations⁸.

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 DEUS) and the lodging of this report to both the Department of Energy, Utilities and Sustainability and to 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.

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;
- PV of distributor operating expenditure saved; and

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.

- PV 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 of 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	PV of Distributor Operating Expenditure Saved	PV of Distributor Capital Expenditure Deferred

11. Review

A decision on the appropriate timing for the review of the 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' / stakeholders' experience with the market based approach in this Code;
- developments in the National Electricity Code process; and
- developments in the Demand Management Services Market.

Appendix 1 Schedule 1: Availability

Appendix: System Support Contract Schedule No. 1- Availability																	
Year:		1		2		3		4		5		6		7		8	
Period no.		from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to
Period (Date)																	
		w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end
time		Capacity Available (MVA)		Capacity Available (MVA)		Capacity Available (MVA)		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)																	

Appendix 1 Schedule 2: Initial and Availability Payments

Appendix 1: System Support Contract Schedule No. 2- Initial and availability payments																					
Year:																					
Period no.	1		2		3		4		5		6		7		8		9		10		
Period (Date)	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from		
	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day		
time	Availability payment (\$/MVAh)				Availability payment (\$/MVAh)				Availability payment (\$/MVAh)				Availability payment (\$/MVAh)				Availability payment (\$/MVAh)				
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Initial payment (\$/kVA)																					
Initial payment (\$lump sum)																					

Appendix 1 Schedule 3: Dispatch Payments

Appendix 1: 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	
Period (Date)	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to		
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time	Dispatch payment (\$/MVAh)				Dispatch payment (\$/MVAh)				Dispatch payment (\$/MVAh)				Dispatch payment (\$/MVAh)				Dispatch payment (\$/MVAh)																					
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Appendix 1 Schedule 4: Compensation Payments (for Failure to Deliver Contracted Capacity)

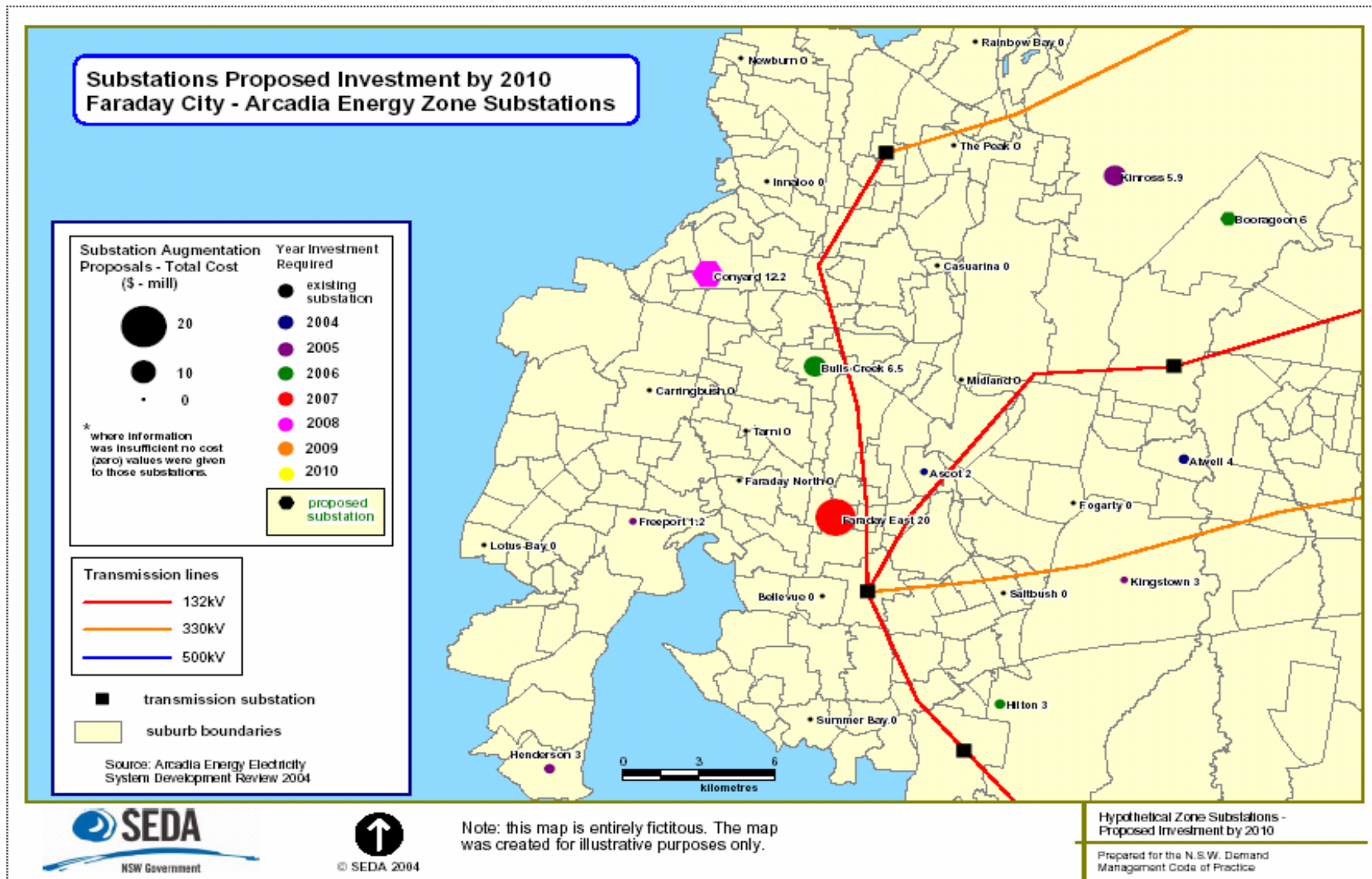
Appendix 1: System Support Contract Schedule No. 4 - Compensation payments (for failure to deliver contracted capacity)																					
Year:																					
Period no.	1		2		3		4		5		6		7		8		9		10		
	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from	to	from		
Period (Date)																					
	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	w/day	w/end	
time	Compensation pay't (\$/MVAh)				Compensation pay't (\$/MVAh)				Compensation pay't (\$/MVAh)				Compensation pay't (\$/MVAh)				Compensation pay't (\$/				
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Appendix 2 Sample ESR Summary Report

APPENDIX 2		SAMPLE ESR SUMMARY REPORT														
SUMMARY OF FORECAST NETWORK SUPPORT REQUIRED																
Current Year		2003														
Forecast Year		2009		Summer			Winter									
Zone Substation/STS	Total Capacity	Current Firm Rating	Forecast year peak load	Spare Firm Cap'y in Forecast Year	Current Firm Rating	Forecast year peak load	Spare Firm Cap'y in Forecast year	Possible Constraint Relief Projects	Project Ref Number	Cost Total (\$m)	Year investment decision required FY	Season of Min Spare Firm Capacity	Spare Firm Cap'y in constraint season MVA	Forecast Average Load Growth* MVA p.a.		
		MVA	MVA	MVA	MVA	MVA	MVA									
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 purchase	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 Map 1 for the Electricity System Development Review



Appendix 3 Sample Map 2 for the Electricity System Development Review

