Advice on Development of a National Framework for Electricity Distribution Network Planning and Expansion

FINAL REPORT

- 4.0
- 13 May 2009

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Abbreviations

ACIL Tasman Consulting	ACIL
ACT Planning and Land Authority	ACTPLA
Allen Consulting Group	ACG
Annual Planning Report	APR
Australian Capital Territory	ACT
Australian Energy Market Commission	AEMC
Australian Energy Regulator	AER
Australian National Long Term Power Quality Survey	ANLTPQS
Bulk Supply Points	BSPs
Carbon Pollution Reduction (Emissions Trading) Scheme	CPRS
Central Business District	CBD
Charles River and Associates	CRA
Commonwealth Scientific & Industrial Research Organization	CSIRO
Customer Average Interruption Duration Index	CAIDI
Demand Management	DM
Distribution Network Augmentation Plans	DNAPs
Distribution Network Services Provider	DNSP
Distribution System Planning Report	DSPR
DM Incentive Scheme	DMIS
Efficiency Benefit Sharing Scheme	EBSS
Electrical Power Research Institute	EPRI
Electricity Distribution and Service Delivery for the 21st Century	EDSD
Electricity Distribution Code	EDC
Electricity Distribution Price Review	EDPR
Electricity Supply Industry Planning Council	ESIPC
Electricity System Development Review	ESDR
Electromagnetic Fields	EMF
Embedded Generation	EG
Essential Services Commission of SA	ESCOSA
Essential Services Commission of VIC	ESCV
Gross State Product	GSP
Guaranteed Service Levels	GSL
Independent Competition and Regulatory Commission	ICRC
Independent Pricing and Regulatory Tribunal	IPART
Investment Review Committee	IRC
Mandatory Renewable Energy Target	MRET
Maximum Demand	MD
Minimum Capital Cost	MCC
Minimum Service Standards	MSS
Ministerial Council of Energy	MCE

Momentary Average Interruption Frequency Index	MAIFI
National Capital Authority	NCA
National Electricity Market	NEM
National Electricity Rules	NER
National Institute of Economic and Industrial Research	NIEIR
Net Present Value	NPV
Network Investment Review Committee	NIRC
Network Management Plan	NMP
New South Wales	NSW
Office of the Tasmanian Energy Regulator	OTER
Online Tap Changer	OLTC
Operations & Maintenance	O&M
Power Factor	pf
Probability Of Exceedence	PoE
Program Management Offices	PMOs
Proprietary Load Flow Package	DINIS
QLD Competition Authority	QCA
QLD Electricity Industry Code	Code
Quality of Supply	QoS
Queensland	QLD
Reliability Assessment Planning	RAP
Request For Proposal	RFP
Service Target Performance Incentive Scheme	STPIS
Sinclair Knight Merz	SKM
Single Wire Earth Return	SWER
South Australia	SA
South Australian Electricity Distribution Code	SAEDC
State Electricity Commission of Victoria	SECV
Substation Capacity	SC
Sub-transmission Network Augmentation Plans	SNAPs
Sub-transmission Substation	STS
System Average Interruption Duration Index	SAIDI
System Average Interruption Frequency Index	SAIFI
TAS Electricity Code	TEC
Tasmania	TAS
Terminal Stations	TSs
Terms of Reference	ToR
Transmission Connection Planning Report	TCPR
Transmission Network Services Provider	TNSP
Value of Customer Reliability	VCR
Value of Lost Load	VoLL
Victoria	VIC

Executive Summary

The Australian Energy Market Commission (AEMC) engaged Sinclair Knight Merz (SKM) to prepare a background information report on the various jurisdictional requirements on, and planning processes undertaken by electricity Distribution Network Services Providers (DNSPs) operating in the National Electricity Market (NEM). This report represents a detailed analysis of the similarities and differences of a wide range of standards, processes, and activities that are followed by jurisdictional regulators and DNSPs in analysing and planning for augmentation and expansion of their distribution networks.

The report is wide-ranging in terms of the subject matter that it is covering, and a number of subjects involve complex engineering and technical concepts. We have attempted to write the report in language that a non-technical person can comprehend, and we have relegated much of the detailed technical explanation to the Appendices. There is a further level of detailed analysis in terms of computer based load flow studies, load forecasting models, energy at risk modelling, and reliability and quality of supply (QoS) calculations which we have not included in the report for reasons of clarity, however it is important for the reader to be aware of its existence.

The following sections provide a summary of SKM's key findings and observations, and for clarity purposes we have grouped them under the following headings:

- Security of Supply and Planning Standards;
- Reliability and QoS Standards;
- Maximum Demand (MD) Forecasting Methodologies;
- Demand Management (DM) and Embedded Generation (EG);
- Assessment of potential market benefits

Security of Supply and Planning Standards:
Generally speaking, jurisdictional regulators have not played a direct role in setting security of supply and planning standards for the DNSPs. In New South Wales (NSW) the standards have been set by the Shareholding Minister through an Act of Parliament, while in Queensland (QLD), Victoria (VIC), South Australia (SA), Tasmania (TAS), and the Australian Capital Territory (ACT), the standards are determined predominantly by the DNSP themselves. The following are our key findings in relation to these standards:

1) While the processes for planning and augmenting the networks of DNSPs are similar, different security of supply and planning criteria are used from State to State and DNSP to DNSP to trigger capital projects for reinforcing the networks (summarised in Appendix A).

2) While the Victorian DNSPs use a probabilistic approach, with some second order deterministic limits, the DNSPs in the other States use a predominantly deterministic set of criteria (known generically as N-1) as the initial trigger to determine capital project timing. Some non-Victorian DNSPs then apply a second order probabilistic approach (e.g. accept risk of loss of supply for 1% of time, or other), but these still tend to be deterministic in nature.
3) In applying their probabilistic approach to determining optimum timing for reinforcement of the system, the Victorian DNSPs value the probability weighted cost of "energy not supplied" at a level which reflects the weighted customer cost, and then compares this with the annualised cost of the augmentation project to determine the optimum timing of the project.
4) We have noted some differences in the details of the application of the probabilistic criteria in VIC, and we note also that the average outage rates used do not appear to reflect increasing fault rates with increasing age of assets.
5) In NSW the predominantly deterministic criteria are gazetted licence conditions that DNSPs must comply with (either immediately, or at some future time), while in QLD the predominantly deterministic criteria are an outcome of a 2004 report to the Government titled Electricity Distribution and Service Delivery for the 21st Century (EDSD).
6) In recent years both CitiPower (VIC) and EnergyAustralia (NSW) have sought to have the security of supply to their respective central business districts (CBD) increased.
7) There is no easy way to directly compare the resulting supply security that comes from both the deterministic and probabilistic methodologies, but there is also no evidence that either method produces a superior outcome. Intuitively, the probabilistic approach should produce an optimum outcome in the timing of augmentation (the scope and cost will be unchanged), provided valid community cost of un-served energy is applied. This cost of un-served energy may be different from State to State.
8) SKM's research to date indicates that the majority of DNSPs studied comply broadly with the requirements of the Ministerial Council of Energy (MCE), in that they:
   - Perform an annual planning process;
   - Make publicly available an annual planning report (APR), which has a five year planning horizon;
   - Make a case by case assessment of the most economic options for system expansion and augmentation.

9) Although ActewAGL (ACT) undertake an annual planning process, they are not required under their jurisdictional obligations to make the results publicly available.

10) Where DNSPs do make APRs publicly available, the format and content detail is different from State to State, and to a lesser extent from DNSP to DNSP within a Jurisdiction.(VIC – APRs, QLD – Annual Network Management Plans (NMP), NSW – Annual Electricity System Development Reports, SA – Electricity Supply Industry Planning Council (ESIPC) APR TAS – Annual Distribution System Planning Report [DSPR]).
11) The scope of planning responsibility of Aurora (TAS) is different to other DNSPs and is impacted by the ownership boundary between Aurora and Transend (the Transmission Network Services Provider [TNSP] of TAS). Unlike other Australian DNSPs who are responsible for planning and operating sub-transmission (e.g. 33 kV, 66 kV) and transmission (e.g. 110 kV, 132 kV) Aurora mainly takes supply from the 11 kV and 22 kV bus-bars of Transend sub-stations.
12) In States other than VIC, the planning responsibility for connection to the transmission network is the responsibility of the relevant TNSPs (in consultation with the DNSPs). However, the Victorian arrangements for transmission connection planning differ from those in other States. In essence, under their licence obligations the Victorian DNSPs have responsibility for planning future transmission connection assets. The full details of the arrangements are provided in the 2008 Joint DNSP Transmission Connection Planning Report (TCPR). This report is provided annually and is publicly available on the websites of each Victorian DNSP.

Reliability and Quality of Supply Standards

Jurisdictional regulators and responsible Government departments have placed a high degree of emphasis on, and involvement in, setting targets for end customer reliability and customer service standards. There is also some involvement in monitoring and setting targets for QoS, but this area is much more subject to specified criteria in relevant Australian Standards.

With regard to reliability of supply, and specifically target setting for System Average Interruption Duration Index (SAIDI) / System Average Interruption Frequency Index (SAIFI) / Customer Average Interruption Duration Index (CAIDI) / Momentary Average Interruption Frequency Index (MAIFI), these are covered by the Electricity Distribution Code (EDC) and / or DNSP Licence Conditions in each State / Territory jurisdiction. While there is a requirement to monitor and report on reliability of supply in all jurisdictions, the level of reporting and the amount of detail provided varies dramatically from jurisdiction to jurisdiction. The highest level of detailed reporting is evident in VIC, where there is a mandated bonus / penalty scheme in place (the S-factor scheme), while the lowest level of reporting is evident in the ACT where reporting of system reliability and quality is not required.

Other key findings in this area were:

13) While Schedule 5.1 of the National Electricity Rules (NER) specify certain performance requirements of distribution networks, these are mainly QoS criteria, and there are numerous other quality and reliability criteria imposed, or followed by DNSPs, at State jurisdictional level.
14) Fortunately, most DNSPs appear to have adopted the Australian Standard AS/NZS 61000.3.7:2001 for measuring and reporting QoS criteria.
15) The full range of reliability and QoS standards imposed on, or adopted by, DNSPs in the NEM are summarised in Appendix B. While reliability of supply (SAIDI / SAIFI, etc.) has been proactively monitored, analysed and reported on for several years, QoS monitoring and measurement is relatively new at the distribution level.
16) Only in VIC is it mandated that DNSPs must monitor QoS (at the bus-bar of each zone substation, and at the end of the longest feeder out of each zone sub-station).
17) While there are well developed frameworks emerging in the NEM for the measurement and reporting of reliability statistics, there is a need also to understand that there are underlying differences in the reliability able to be delivered from the different distribution systems operated by the DNSPs. Material differences occur as a consequence of the historical selection of primary distribution voltages, and the percentage of undergrounding that has occurred over the years.
18) Reliability measurement and reporting is most advanced in VIC, where the S-factor system has been in place since 2001, although the reliability recording and reporting systems in most DNSPs is at a reasonably consistent and high standard.
19) The reporting of actual reliability performance varies significantly from jurisdiction to jurisdiction, in terms of the level of disaggregation and the planned works to overcome poor reliability in specific areas, or on specific feeders.

Maximum Demand Forecasting Methodologies:

One of the key activities, and arguably the starting point of the DNSP system planning process is the preparation of a suite of demand forecasts at various levels on the distribution system, to enable the system to be augmented in a timely fashion to meet future demands for electricity. This process must be co-ordinated with the process for identifying and implementing DM and EG solutions to meet future demand growth.

At its most basic level, demand forecasting has historically involved conducting a trend analysis of historical loads to produce the future forecast. However, the level of sophistication, complexity, and scenario analysis, available to undertake demand and energy forecasting has increased considerably in recent years, and it is now common for utilities to apply standard weather corrections, econometric modelling, probabilistic techniques and scenario analysis to their forecasting processes. It is SKM's observation however that there are material differences in the way that DNSPs conduct their demand forecasting processes that require more alignment.

SKM's other key findings in this area were:

20) All DNSPs researched commented that demand forecasting was a key element and input into the system planning process. By comparing their spatial MD forecasts with the firm capacity of substations and sub-transmission / distribution feeders, DNSPs determine the trigger point in time at which they will undertake system augmentation (subject to any additional risk assessments and probabilistic judgements they may make).
21) SKM noted a considerable degree of variation in the sophistication and level of detail that DNSPs undertake in preparing their "spatial" load forecasts (as distinct to their system wide MD forecast). These differences are captured to some extent in attached Appendix C, although the demand forecasting process is often not sufficiently transparent to enable all of the differences to be identified.
22) The main areas of difference or uncertainty in the demand forecasting areas were:
    - Whether DNSPs adequately reconciled spatial demand forecasts with the system wide forecast?
    - Whether DNSPs used an appropriate mix of methodologies to underpin their spatial forecasts?
    - Whether the concept of 10%, 50% and 90% probability of exceedence (PoE) forecasts are consistently developed and applied at the spatial level?
    - Whether historical MDs are weather corrected (or otherwise adjusted) before use in trend or regression analysis at the spatial level?

Demand Management and Embedded Generation

An important consideration in the system planning process is the extent to which DM strategies and EG projects may assist in meeting future demand requirements on the distribution system, and the extent to which such opportunities may defer or possibly eliminate the need for certain network augmentation.

Historically, DNSPs have developed in-house DM and alternative energy strategies, but are being increasingly required to create the transparency and opportunity for DM and EG opportunities to be proposed and implemented by external proponents. Only one State jurisdiction (NSW) has to date implemented a formal process for providing information to the marketplace, calling for Requests for Proposals, and a structured evaluation process. Other States and DNSPs have a less rigorous approach for dealing with DM and EG opportunities on a case by case basis.

SKM's other key findings and observations in this area are:

23) The majority of DNSPs have internally developed DM programs and projects which they are pursuing at any point in time (they can be considered to be "proponents" in this sense).
24) Most if not all DNSPs have well developed technical and performance criteria for the connection of EG onto their distribution networks, and often these requirements are seen by external proponents to be barriers to non-network solutions. In particular, the contribution that embedded generators make to increased fault levels on the distribution systems is a difficult and costly technical barrier to overcome.
25) NSW is the only jurisdiction to have implemented a formal regulatory framework for handling DM and EG opportunities. The NSW Demand Management Code of Practice provides guidelines to the DNSPs for the procedures to be followed, and Independent Pricing and Regulatory Tribunal's (IPART) DM Incentive Scheme (DMIS) is designed to neutralise potential regulatory disincentives to implementing cost effective DM measures.
26) There are examples in other States where DM and EG projects have been implemented, or approved for implementation, with regulatory approval for network support payments.

Assessment of Potential Market Benefits:

27) After reviewing the provisions of the existing Regulatory Test and associated Application Guidelines, SKM has concluded that the Test in its current form is unsuitable for application to, and in fact specifically excludes, a wide range of reliability and refurbishment / replacement projects that DNSPs implement.
28) The thorough assessment of the economic benefits of a wide range of DNSP projects requires a sound methodology and approach to valuing the community cost of energy not supplied. Such an approach has been used in VIC since about 1997, and is an integral part of the probabilistic planning approach. While such a concept has been considered, along with the concept of "customer willingness to pay" neither concept has been formally adopted in other States to the best of our knowledge. SKM sees no reason why the community cost of energy not supplied could not be applied in a practical way to deterministic planning.

29) The types of costs and benefits that may be applied to distribution projects under the “market benefits” limb of the Test are, with minor modifications, appropriate and sufficiently comprehensive for application to distribution projects.

30) Apart from projects which have already been submitted under the Regulatory Test, there is minimal material available in the public domain about the specifics of the economic analysis techniques used by DNSPs to evaluate distribution augmentation projects of varying size ($) and categories (e.g. security, capacity, reliability). SKM would expect that larger discreet distribution and sub-transmission projects would be evaluated using a Net Present Value (NPV) methodology, while smaller primary distribution voltage projects may be evaluated based on a minimum capital cost (MCC) approach.

31) Attached Appendix D, which is currently an unpopulated pro-forma could be used to gather information about the type of costs and benefits that may be included in the economic evaluation of options for distribution projects of varying size, type, and complexity.

1. Introduction

SKM has been engaged by the AEMC to conduct a review of the planning processes undertaken by electricity DNSPs in the NEM

1.1. Ministerial Council of Energy

The review is in response to a direction dated 17 December 2008 from the Ministerial Council on Energy (MCE) to the AEMC to conduct a review into the current electricity distribution network planning and expansion arrangements which exist across the jurisdictions in the NEM, and propose recommendations to establish a national framework for distribution network planning and expansion. The AEMC is also to provide detailed advice on the implementation arrangements for a National Framework, which may include changes to the NER.

1.2. Review to be Conducted in Two Stages

The review by SKM is to be conducted in two stages, as follows:

Assignment 1: - A review and preparation of a background report on the planning processes undertaken by electricity DNSPs in the NEM. This report and attachments represents the main deliverable against Assignment 1.

Assignment 2: - Informed advice to the AEMC on distribution network planning and expansion in the NEM. This advice, consultation, and attendance is expected to be required over the period from March to September, 2009.

1.3. AEMC Scoping and Issues Paper

The AEMC issued a Scoping and Issues Paper *"Review of National Framework for Electricity Distribution Network Planning and Expansion"* dated 12 March 2009. The scoping and issues paper outlines the broader scope of the assignment from the MCE and is designed to elicit comment on the scope of the review, and to identify and seek views on a range of issues that require resolution in recommending a national framework.

1.4. Previous Report by NERA / Allen Consulting Group (ACG)

NERA Economic Consulting and the Allen Consulting Group published a joint report titled *"Network Planning and Connection Arrangements – National Frameworks for Distribution Networks, August 2007"* in response to a commission from the MCE Standing Committee of Officials to provide advice on a national framework for electricity distribution network planning and connections. While the NERA / ACG report has been used as background material it has not formed the basis of any analysis or conclusions drawn by SKM.

1.5. Information Sources

In addition to its own general knowledge about the planning augmentation, expansion, maintenance, and reliability of Australian electricity distribution systems, SKM has used three primary sources of publicly available information in researching, analysing, and compiling material for this report.

- Various Federal and State based legislative instruments and Act's (e.g. NER, Electricity Acts, Industry Codes, Guidelines, etc.).
- Various DNSP documents, and attachments thereto, relating to regulatory submissions and price control resets (e.g. Australian Energy Regulator [AER] review of NSW distributors).
- Various documents contained on DNSP and other websites (e.g. Victorian DNSP APRs, Reliability Performance Reports, etc.).

2. Objective & Scope

The main objective of this report is to provide an outline of the current processes undertaken by electricity DNSPs in each of the jurisdictions in the NEM when planning and expanding their networks. The terms of reference (ToR) specifically exclude considerations of "connection arrangements". The report is intended to provide background material and information, as distinct from making any specific recommendations or findings in relation to jurisdictional requirements or DNSP planning processes.

Further, AEMC's ToR required that the report provide:

- A conceptual framework of how distribution network planning is undertaken in the NEM.
- A description of the jurisdictional planning / reliability standards, highlighting the differences in how the standards are determined across the States.
- An understanding of how DNSPs plan to meet their jurisdictional standards.
- A description of how DNSPs engage with providers of non-network alternatives during their planning processes, and
- An evaluation of the potential for market benefits (i.e. benefits above the reliability standards) from augmentations to the distribution network. The potential types of market benefits are listed under the current Regulatory Test.

In addressing the ToR, this report is structured in the following manner:

- **Section 3 -** Addresses the Network Performance Standards specified in the NER, specifically those contained in Schedule 5.1, and which relate to DNSPs.
- **Section 4 –** Provides a general description of the assets and systems that constitute a typical distribution system. Also provides a structure of the processes and activities of a conceptual framework for distribution planning.
- **Section 5 -** Summarises the various Acts, Codes, Licence Conditions and Standards that exist in each of the States of the NEM, and the specific obligations that they place on the DNSPs in respect to conducting distribution planning processes, and communicating their plans and performance to the broader community.
- **Section 6 -** Summarises the various Acts, Codes, Licence Conditions and Standards the apply in each of the States of the NEM, and the specific obligations that they place on the DNSPs in respect to meeting targets for distribution system reliability and QoS standards, and communicating their plans and performance to the broader community.

- **Section 7 -** Contains a DNSP by DNSP summary of the annual planning processes, APRs, demand forecasting methodologies, DSM and EG considerations, and lists of relevant publications and reports that are either available publicly, or are submitted for regulatory scrutiny by each DNSP.
- **Section 8 –** Provides commentary on the relevance and applicability of the Regulatory Test to distribution, as well as some observations about the range of costs and benefits that would be required to adequately assess the potential market benefits of distribution projects.
- **Section 9 -** Provides a summary of the Dispute Resolution Procedure under the NER, and discusses the relevance and applicability of this procedure to the National Framework for Electricity Distribution Network Planning and Expansion.
- **Appendix A -** Presents a summary of the System Security Criteria and Planning Standards of each of the DNSPs, together with a set of explanatory notes on the application of the criteria / standards.
- **Appendix B -** Presents some basic network statistics for each DNSP, together with details of their system reliability and QoS performance obligations and reporting requirements.
- **Appendix C -** Details SKM's best assessment of the key features of the demand forecasting methodologies adopted by each DNSP in conducting its system planning processes. We have attempted to differentiate between the methodologies used at the system wide level, and those used to produce "spatial" load forecasts for bulk supply and zone substations, or lower.
- **Appendix D -** Presents a proposed framework for gathering information about the various methods used by DNSPs to conduct economic analysis of alternative options for augmentation / reinforcement of distribution and sub-transmission / transmission systems owned and operated by DNSPs in the NEM. The proposed framework is not yet populated, as this information is not currently publicly available.
- **Appendix E –** Is a diagrammatic representation of a Conceptual Load Forecasting Sub-Process of the Distribution Planning Process, along with notations about best practice characteristics of load forecasting.
- **Appendix F –** Is a diagrammatic representation of a Conceptual Constraints Identification & Options Evaluation Sub-Process, along with notations about best practice characteristics.
- **Appendix G –** Is a diagrammatic representation of a Conceptual Capital Approval, Programming & Governance Sub-Process, along with notations about best practice characteristics.
- **Appendix H –** Summarises relevant DNSP Planning Documents, and indicates whether they are publicly available, or for regulatory scrutiny.

3. Requirements of the National Electricity Rules

The ToR require that this report give due consideration to the requirements of the NER, insofar as they relate to the network planning and expansion of distribution systems.

Specifically, Schedule 5.1 – "Network Performance Requirements to be provided or co-ordinated by Network Service Providers" describes the planning, design and operating criteria that must be applied by Network Service Providers to the transmission networks and distribution networks which they own, operate or control.

Schedule 5.1 of the Rules specifies a range of performance requirements that are predominantly QoS parameters, rather than Reliability of Supply. These include:

- **Magnitude of Power Frequency Voltage -** During credible contingency events, supply voltages should not rise above the time dependant limits defined in Figure S5.1a.1 of the Rules;
- **Voltage Fluctuations -** A Network Service Provider must endeavour to maintain voltage fluctuation (flicker) levels in accordance with the limits defined in Figure 1 of AS2279.4:1991;
- **Voltage Harmonic Distortion -** A Network Service Provider must design and operate its network to ensure that the effective harmonic distortion at any point in the network is less than the Compatibility Levels defined in Table 1 of Australian Standard AS/NZS 61000.3.6:2001;
- **Voltage Unbalance -** A Network Service provider must ensure that the average voltage unbalance measured at a connection point should not vary by more than the amount set out in TableS5.1a.1 of the Rules;
- **Minimum Power Factors -** Section 5.3.5 of the Rules defines minimum power factors (pf) that apply at connection points. These are designed to minimise losses and optimise required generation.

Schedule 5.1 of the Rules also addresses other matters such as power transfer capability, credible contingency events, system stability, load shedding, blocking of auto-reclose, and continuous and dynamic ratings, but many of these issues relate predominantly to TNSPs rather than DNSPs.

4. Distribution Planning Process

4.1. Structure of a Distribution System

4.1.1. Transmission / Sub-transmission Voltages

Most DNSPs in the NEM take supply at either 132 kV, 110 kV, 88 kV, or 66 kV from major substations that are owned and operated by the local TNSP. The exception to this is in TAS, where on much of the system Aurora take supply at 11 kV / 22 kV on the secondary side of major substations.

The 132 kV and 110 kV system may be referred to variously as "transmission", or "sub-transmission", depending on the role it plays in supporting higher voltage systems of the TNSP. Generally speaking we will use the term "sub-transmission" to mean 132 kV, 110 kV, 88 kV, 66 kV or 33 kV owned and operated by a DNSP.

4.1.2. Bulk Supply Points

The TNSP substations from which supply is taken are known variously as Bulk Supply Points (BSPs), or Terminal Stations (TSs). Sometimes there are assets of both TNSPs and DNSPs contained within these substations.

4.1.3. Zone and Sub-transmission Substations

The major substations owned and operated by the DNSPs are known as either sub-transmission substations (STSs) or Zone Substations (Z/S). Typical voltage levels include 132 / 11 kV or 22 kV, 110 / 11 kV or 22 kV, 88 / 11 kV or 22 kV, 66 / 11 kV or 22 kV, and 33 / 11 kV. Typically, DNSPs have between 12 (ActewAGL), and up to 200 – 300 of these major substations.

4.1.4. Primary Distribution Systems

There are two commonly used single and three phase primary distribution voltages in the Australian NEM, namely 11 kV and 22 kV. The rural parts of some States are also serviced by 12.7 kV and 19.1 kV single wire earth return (SWER) systems, and there are other voltages to be found (e.g. 5 kV, 6.6 kV), however these are in the minority.

Details of the main primary distribution voltage and some basic system statistics for each DNSP can be found in Appendix B.

4.2. Conceptual Framework for the Distribution Planning Process

While each DNSP within the NEM would have somewhat different planning criteria, different asset boundaries, different system voltages and in some cases, different planning responsibilities, the major steps within the Distribution Planning Process are common and are shown in Figure 1 below.

- **Figure 1 Conceptual distribution planning process**

The main steps and activities typically undertaken within this overall conceptual process are detailed further in Appendices E, F and G.

Note that the conceptual process outlined in Appendices E, F and G has been developed by SKM to be representative of a typical process that might be followed by a DNSP and is not necessarily representative of any particular DNSP in the NEM.

Also listed within Appendices E, F and G are some features or characteristics of various sub-processes which SKM considers are "Best Practice" or "Good Industry Practice". Again, these are not necessarily all common to, or present within the processes of DNSPs within the NEM.

4.3. Load Forecasting (Appendix E)

Load forecasting is arguably the first step in the planning of an electricity system, including the distribution and sub-transmission systems of DNSPs. The conceptual model for the load forecasting sub-process is Appendix E, and is generally undertaken at three distinct levels, namely:

- **System level –** forecasts of MD, customer numbers, and annual energy consumption are normally produced.
- **Regional or major substation level –** forecasts of MD at substation level. These may or not be weather corrected and may or may not be 10% / 50% PoE based. Forecasts at this level are the most useful for identifying system constraints, and opportunities for non-network solutions.
- **Distribution feeder level –** forecasts of MD at exit feeder level. Not normally weather corrected. Some DNSPs do not undertake a forecast at this level. If undertaken, care needs to be taken to exclude temporary switching load transfers.

Note that the conceptual planning process has no context or role at the system level beyond the Load Forecasting sub-process (i.e. in Appendix F and Appendix G).

Further details of the current load forecasting methodologies of DNSPs within the NEM are contained in Appendix C.

4.4. Constraints Identification – Deterministic vs. Probabilistic Planning (Appendix F)

While the processes for planning and augmenting the distribution networks (including identification of system constraints), are similar for each DNSP, they each use a different set of system security and planning criteria as a "trigger point" for establishing the optimum timing of augmentation projects.

The structure and presentation of the various jurisdictional and DNSP documents describing system planning standards and security criteria vary significantly from State to State and utility to utility. In order that direct comparisons can be made between the various jurisdictions, we have translated the underlying planning principles into a single tabular format, with clarifying notes where appropriate. This tabular format is shown in Appendix A, and is based on the Schedule 1 "Design Planning Criteria" contained in the NSW "Design, Reliability and Performance Licence Conditions for Distribution Network Service Providers by the Minister for Energy and Utilities – 1 December 2007".

Further details on the differences between deterministic and probabilistic planning as practiced by the DNSPs can be found in Section 5 of this report.

4.5. Internal Approvals, Works Programming and Capital Governance (Appendix G)

This sub-process represents that stage of the planning process covering final approvals of individual capital projects and capital programs, through to the final installation and commissioning and culminating in the preparation of a post implementation report on the project cost, timing and effectiveness.

In reality, the process will be different in detail from DNSP to DNSP, and the larger DNSPs will have quite extensive and detailed project management reporting and financial systems.

4.6. Co-ordination of TNSP and DNSP Planning

Contained within the constraints identification sub-process (Appendix F) is an activity termed "Co-ordination of Joint Planning Studies with TNSPs". This is an activity which we know is undertaken but there is little documented information about the process in the public area.

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We understand that Joint Planning Committee meetings take place regularly between TNSPs and the DNSPs in each State, and that these committees have joint responsibility and accountability for optimising the project scope and timing of major projects which have a "transmission (TNSP)" component and a "distribution (DNSP)" component.

The outworking of these committees would result in the production of proposed system augmentation reports suitable for submission under the Regulatory Test regime.

Somewhat different, joint TNSP / DNSP Planning processes and responsibilities exist in VIC and TAS and these are detailed in Sections 5.2.3 and 5.3.2 of this report.

4.7. Economic Analysis of Augmentation Options (Appendix F)

Typically, the economic evaluation of alternative augmentation options for projects at the sub-transmission and transmission levels are based on the NPV methodology applied over a 10 – 20 year timeframe (longer if necessary, rarely shorter). By comparison, the economic evaluation of options at the primary distribution level (typically 11 kV / 22 kV) are often conducted based on MCC, with consideration given to project options involving different amounts of overhead / undergrounding different routes for feeders, different connection arrangements, etc.

We have found that there is no uniform approach to this issue across DNSPs and it is SKM's view that the following list of criteria, costs, and benefits should be applied more broadly in the economic evaluation of major distribution augmentation projects.

- **Table 1 SKM proposed criteria, costs and benefits for major distribution augmentation project**

	Project Type	
	Transmission / sub-transmission	**Primary distribution**
Economic evaluation methodology	NPV	NPV or MCC, (as appropriate)
Period of study	15 – 20 years	0 – 5 years
Costs / benefits to be included:		
▪ Capital costs	Yes	Yes
▪ Annualised operations & maintenance (O&M) costs	Yes	Optional
▪ Age related trend in O&M costs	Yes	Optional
▪ Annualised cost of losses	Yes	Optional
▪ DM / EG network support benefits (deferral of network augmentation & reduced losses)	Yes	Optional (subject to simple screening test)
▪ Differences in the probability weighted value of customer reliability (energy not supplied)	Yes	Optional

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	Project Type	
	Transmission / sub-transmission	**Primary distribution**
▪ Sensitivity analysis (discount rates, load forecast, etc)	Yes	No

4.8. Consideration of Demand Management and Embedded Generation Opportunities

This activity is shown in the early stages of the Capital Approval, Programming and Governance sub-process (Appendix G), however it could equally be triggered at the "DM / EG External Consultation Process" in the Constraints Identification sub-process (Appendix F).

In reality, DNSPs themselves are proponents of certain DM initiatives and projects which would be embedded at various stages within the planning process. The two activities identified above are where they would most likely initiate contact with external DM / EG proponents.

4.9. Integration with other Capital Works

The process shown within Appendix E and Appendix F, relate specifically to projects which are triggered when the forecast MD at a certain point on the network exceeds the assigned rating of a component or components at that point on the network (e.g. MD exceeds the cyclic rating of a transformer). There are several other criteria / reasons why capital projects might be triggered, including:

- Fault levels being exceeded;
- Excessive steady state voltage drop;
- Improving the security of supply;
- Improving reliability;
- Replacing / refurbishing ageing and potentially unreliable assets;
- Upgrading / replacing secondary control and protection systems.

At some point in the planning process, these many and varied proposed projects and their associated drivers need to come together, be prioritised and co-ordinated so that the scope and timing of all projects are optimised. This activity is shown for convenience at the end of the Conceptual Constraints Identification Sub-process (Appendix F), but in reality it occurs throughout the whole cycle of the planning process.

4.10. Production of Annual and Five Year Capital Works Programs

Virtually all, if not all DNSPs in the NEM produce annually a five year works program and capital budget, although the contents and detail will vary. It is at this point in time that the most current information, including the most up-to-date load forecast and the nature and timing of system constraints, exists to communicate DM / EG opportunities to external proponents.

4.11. Conduct of Regulatory Test

The activity "Conduct Regulatory Test Consultation Process" is shown at the start of the Conceptual Capital Approval, Programming and Governance Sub-process (Appendix G), however in reality the timing of this activity will be determined to allow an adequate lead-time for design and construction of the project. It will not necessarily coincide with the issue of five year Capital Expenditure Budgets as shown in the flowchart.

5. Jurisdictional Distribution Planning Requirements

5.1. South Australia

5.1.1. Electricity Supply Act 1996

The Electricity Supply Act 1996 is the primary legislation covering the performance of the only DNSP in SA - ETSA Utilities. Operating in the South Australian jurisdiction of the NEM, ETSA Utilities is required to comply with technical standards in the NER. In particular, requirements relating to reliability and system security contained in Schedule 5.1 of the Rules relevant to planning for future electricity needs.

Under its license condition, ETSA Utilities is also required to comply with the service obligations imposed by the South Australian Electricity Distribution Code (SAEDC).

As a DNSP within the NEM, ETSA Utilities will need to consult with registered participants and interested parties prior to undertaking any augmentation with an estimated cost in excess of $2M ('Reasonable Test').

In SA, the generation and transmission planning is covered by the ESIPC, which has the responsibility under the NER to publish the APR to inform the South Australian electricity customers the adequacy of the electricity supply system to meet the medium and long-term needs. This APR is released in June each year.

5.1.2. System Planning Criteria

As mentioned earlier, ETSA Utilities is required to comply with the service obligations imposed by the SAEDC.

The planning criteria adopted by ETSA Utilities are generally deterministic, with substation overloads identified based on forecast peak load under contingency (N-1) conditions.

SKM noted that the SAEDC published by Essential Services Commission of SA (ESCOSA) does not provide specific guidelines for the design and operation of metropolitan 66 kV systems. Under the current regulatory incentives for supply reliability, ETSA Utilities seeks to maintain the required reliability level by keeping 'N-1' capacity on the metropolitan meshed 66 kV sub-transmission network. However, this 'N-1' condition is based on the peak load through the line exceeding emergency rating, rather than the normal rating in the conventional N-1 condition.

When all lines are in service (i.e. 'N' condition), ETSA Utilities design their lines so that the normal rating exceeds the forecast peak load. As such, depending on the extent to which the normal rating exceeds the forecast peak load, the N-1 condition may or may not be satisfied.

ETSA Utilities state in their Electricity System Development Plan that *'...the Network Planning Criteria incorporate the objectives of establishing and maintaining compliance with all applicable Statutes, National and International Standards and Codes of Practice, the Electricity Act, and satisfying National Electricity Market obligations…"*. In particular, the criteria embody generally accepted as appropriate internationally or throughout Australia by the electricity supply industry, and to ensure security of electricity supply to customers.

ETSA Utilities conduct joint planning with the transmission utility ElectraNet and produce a document - Connection Point Management Plan which outlines the predicted required timing and scope of future Connection Point upgrades.

ETSA Utilities is required by the EDC to provide customers with voltage levels that comply with Australian Standard AS60038 – 2000, Standard Voltages.

ETSA Utilities' substations are designed to supply peak normal load on normal cyclic rating and peak load for the worst single substation contingency (N-1 event). The method of achieving N-1 capacity depends on the size, location, and nature of the load.

To the best of SKM's knowledge, ETSA Utilities is not required to continuously monitor power quality indices. However, QoS statistics extracted from customer complaints are submitted to the Regulator on a quarterly and annual basis. ETSA Utilities also reports and compares the time taken to investigate and remediate power quality problems against trial targets.

5.1.3. Non-Network Solution

ETSA Utilities has strict requirements for EG, particularly those designed to address sub-transmission constraints. The availability of EG capacity must be guaranteed and pre-dispatched at the times when it is needed, which can be quite difficult to achieve given that most EG has energy supplied from renewable sources such as wind or solar. SKM is aware that changes have been made to the NER to include a new semi-scheduled classification particularly for wind generation.

It is not clear from the APR if there is any Code of Practice that is application to ETSA Utilities in relation to non-network solutions, however, it appears that ETSA Utilities supports the DM solution such as load shedding contracts, and has published its latest developments and trial results on its website.

5.2. Victoria

5.2.1. Electricity Supply Act 2000

The Electricity Supply Act 2000 is the primary legislation covering the obligations and performance of the five DNSPs in VIC (SP AusNet, Jemena, CitiPower, Powercor and United Energy). The regulatory power in terms of licensing, price and service performance are set out in the Essential Service Commission Act 2001 to safe guard the interests of Victorian consumers with regard to price, quality and reliability.

The Victorian electricity regulatory framework was established in 1994, following the disaggregation of the industry (State Electricity Commission of Victoria [SECV]).

From 1 January 2009, the AER assumed responsibility for the economic regulation of Victorian DNSPs. This function was previously the responsibility of the Essential Services Commission of VIC (ESCV). The AER will also assume responsibility for some related non-economic functions.

5.2.2. System Planning Criteria

The Victorian DNSPs are required under their license condition to submit to ESCV, and to publish on its website, a DSPR detailing the plans over the next five years to meet forecast demand and reliability standards. These requirements are specified in clause 3.5 of the EDC.

The planning criteria adopted in VIC are predominantly probabilistic in nature. The details of this approach can be found in the 2008 Joint DNSP TCPR prepared jointly by all the Victorian DNSPs. The probabilistic planning approach can be summarised as follows:

- Detailed assessment of forecast MD against N and N-1 ratings;
- Calculation of both “Energy at Risk” and “Hours at Risk” in cases where the forecast MD is greater than the station / plant ratings (under outage conditions) – based on measured Load duration curves. A brief discussion regarding the Load duration Curve is provided below;
- Estimation of the probability of an outage coincident with the forecast MD to give the “Probability Weighted Energy at Risk”. Forced outage rates are based on industry statistics for each equipment category;

- Estimate of the cost to the community of the resultant "probability weighted" energy at risk. This is based on the most recent estimates for the Value of Customer Reliability (VCR) from the Charles River and Associates (CRA) cost survey for different consumer classes. The classes and costs are shown in the following Table (from Victorian 2008 TCPR):

Sector	**VCR ($/MWh)** (Source: CRA, *Assessment of the Value of Customer Reliability*, August 2008)
Residential	$13,250
Commercial	$90,760
Agricultural	$111,060
Industrial	$36,070
Composite- all sectors	**$47,650**

- Using these costs, a sector weighted cost for VCR for each site can be determined based on estimated customer composition;
- This sector weighted cost is then multiplied by the Probability Weighted Energy at risk to provide the "Expected Cost of Un-served Energy";
- In simplistic terms, if the "Expected Cost of Un-served Energy" is greater than the annualised cost of the network augmentation then the project is justified, i.e. the expected cost to the Community with no augmentation is greater than the cost of augmentation.

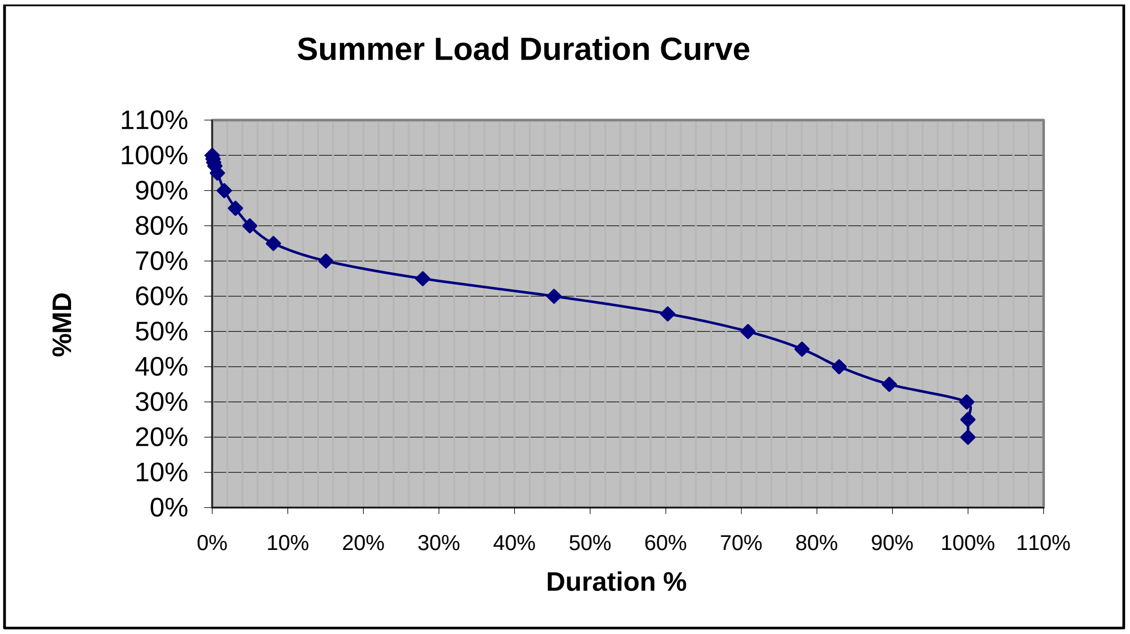
Probabilistic Planning recognises that extreme loading conditions may occur for only a few hours in each year and that it may be uneconomic to provide additional capacity to cover for an outage during this short period. Inherent in the Probabilistic Planning approach is the acceptance that "there are conditions under which all the load cannot be supplied with a network element out of service" (ref CitiPower 2008 Distribution Planning Report section 2.2).

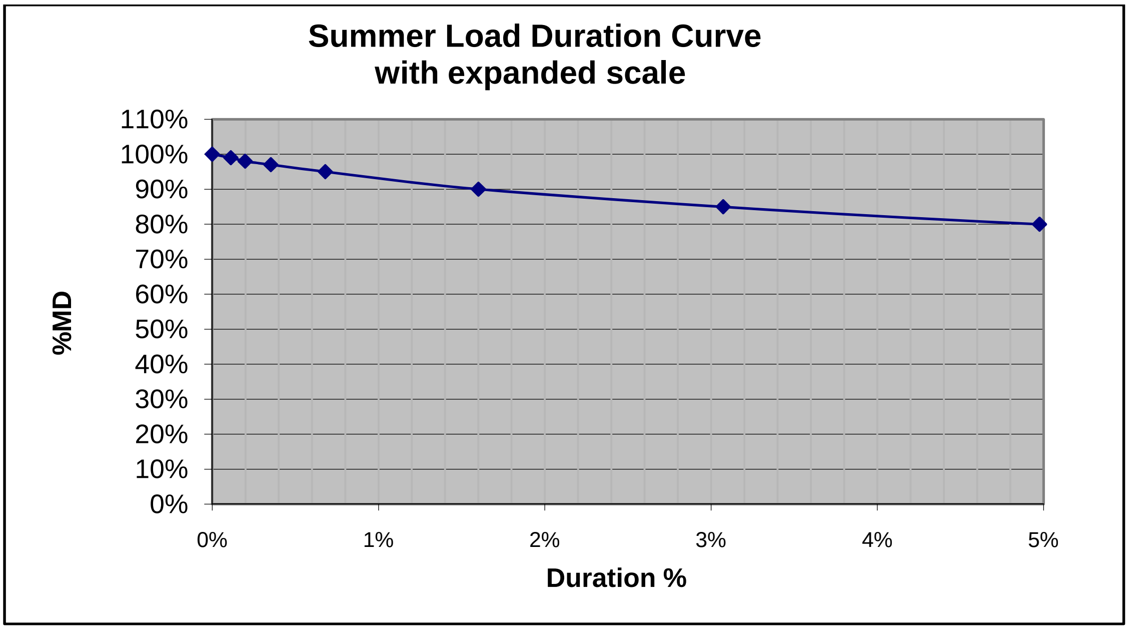
The Probabilistic Planning approach is often overlaid with deterministic planning, examples of which are:

- Use of cyclic or emergency ratings;
- Load Transfer capabilities (remote switching and manual switching);

- Provision of spares to limit outage durations.

Load Duration Curves





These figures show the measured Summer Load Duration curve for a substation. The curves demonstrate that loading above 90% of MD occurs for less than 2% of the time and above 95% MD for less than 0.7% of the time (or 15 hours over the summer period). It is this extreme needle peak (typical of most substations) that provides the justification for probabilistic planning.

Victorian DNSPs are likely to be subject to new forms of regulatory control in their 2011–15 price determination. The AER is expected to set out regulation in relation to the following:

- the classification of services;
- the application of a service target performance incentive scheme (STPIS);
- the application of an efficiency benefit sharing scheme (EBSS) and;
- the application of a DMIS.

These changes are likely to impact the current planning process adopted within DNSPs in VIC.

The DNSPs are subject to a performance incentive scheme called the S-factor scheme. The scheme provides rewards or penalties for meeting or failing to meet performance targets (based on past performance) relating to reliability and customer service. The rewards / penalties are calculated as a percentage of the annual revenue.

VIC is the only State to have mandated direct monitoring of power quality, although regulatory bodies in all States require regular reporting of power quality information derived from customer complaints.

5.2.3. Victorian Arrangements for transmission connection planning

The Victorian arrangements for transmission connection planning differ from those in other States. The full details of the arrangements are provided in the 2008 Joint DNSP TCPR. In essence, under their licence obligations the DNSPs have responsibility for planning the transmission connection assets:

Clause 14 of each DB's Distribution Licence states:

> "The ***Licensee*** is responsible for planning, and directing the augmentation of, ***transmission connection assets*** to assist it to fulfil its obligations [to offer connection services and supply to customers] under clause 6."

The licence defines "transmission connection assets" as:

> "those parts of an electricity transmission network which are dedicated to the connection of customers at a single point, including transformers, associated switchgear and plant and equipment."

Transmission connection assets are those parts of the transmission system which are dedicated to the connection of generator(s) or customer(s) at a single point within the transmission system. In Victoria:

- the DBs have responsibility for planning and directing the augmentation of the facilities that connect their distribution systems to the Victorian shared transmission network;[5] and
- VENCorp is responsible for planning and directing the augmentation of the shared transmission network.

Figure 1 below illustrates the distinction between the shared transmission network and transmission connection assets.

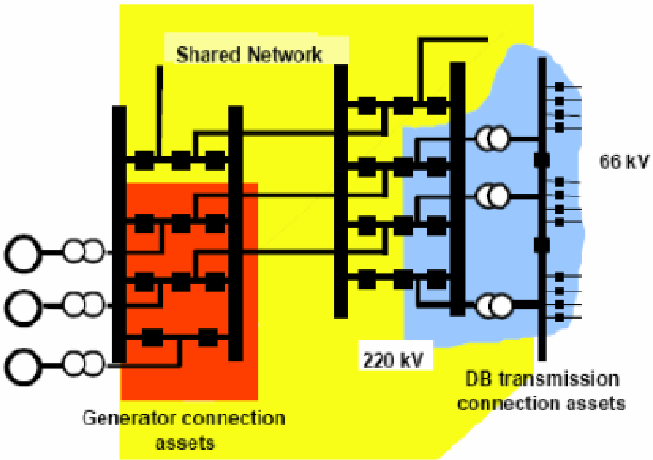


Figure 1: Shared network and connection assets in a notional network
(Source: *VENCorp Electricity Annual Planning Review*, 2007)

To assist with this planning, and taking into account the fact that many transmission connection assets are shared between DNSPs, a pragmatic approach was taken to develop a joint planning document covering all transmission connection assets in VIC. The latest version of this document is the “2008 Joint DNSP TCPR”. This report is provided annually and is publicly available on the websites of each Victorian DNSP.

The TCPR provides information for every Terminal Station relating to Load forecasts (10 years outlook using both 50th and 10th percentiles), Energy at Risk, Expected Cost of Un-served Energy, network solutions and possibilities for non-network solutions such as Demand Side Management or EG.

5.3. Tasmania

5.3.1. Electricity Supply Act 1998

The Electricity Supply Industry Act 1998 is the primary legislation covering the performance of the only DNSP in TAS – Aurora Energy. Operating in the TAS Jurisdiction of the NEM, Aurora is required to comply with technical standards in the TAS Electricity Code (TEC), the NER schedule 5.1 and the applicable Australian Standards. In particular, requirements relating to reliability and system security contained in Schedule 8.1 of the TEC relevant to planning for future electricity needs.

Aurora has the obligation under the TEC to prepare a performance report to the office of the Tasmanian Energy Regulator (OTER) every year. The latest report available is 2007-08, covering performance related to reliability, quality, call centre performance and financial performance.

5.3.2. Tasmanian Planning Report

Aurora is required, under the Tasmanian Electricity Code (TEC), to produce an annual DSPR to provide:

- Information to existing and prospective network users and other interested parties about expected changes to Aurora distribution network during the next five years;
- Compilation from the results of the Annual Planning Review conducted jointly by Aurora and Transend Networks Pty Ltd (Transend);
- Issues, constraints and planning associated with network connections with Hydro TAS Pty Ltd (Hydro Tasmania) assets located on mainland TAS.

The notable highlights of this DSPR are:

- Aurora does not apply strict deterministic planning standards (i.e. N-1) across its distribution networks for system development. Instead, it adopted a probabilistic approach similar to 'energy at risk' analysis used in VIC;
- The new distribution network supply reliability standards classify each supply area or community into one of five supply reliability categories; the boundaries of four of these categories are defined on the basis of annual electricity consumption density:
  - High Density Commercial (Hobart, Launceston, Burnie);
  - Devonport, Rosny, Glenorchy, King's Meadows and Kingston);
  - Urban and Regional Centres;
  - Higher Density Rural; and

- Lower Density Rural.

- Accordance with NER Clause 5.6.2;
- Security of supply Planning:
  - Group firm philosophy or a deterministic planning standards, e.g. "N-1";

- System Performance Planning:
  - Voltage regulation range of + 6% and – 6% of the nominal HV voltage and a LV voltage range of 230/400V +10% and –2%;
  - Power quality standards are recognised in accordance with the TEC, NER and applicable Australian Standards; and
  - Tasmanian Reliability Performance Standards.

- Capacity Planning:
  - Minimum 10 year load forecast planning, with consideration to extrapolated forecasts covering the average life of the key asset components;
  - Maximum average loading considerations for distribution feeders facilitating HV feeder interconnectivity;
  - - 22 kV – 10 MVA continuous and 15 MVA (typically one hour) emergency;
    - 11 kV - 5MVA continuous and 7.5 MVA (typically one hour) emergency.
  - A prudent range of standard conductor size for overhead conductors and underground cables, sized to meet the networks design criteria and feeder topography.

- Zone substations not necessarily adopt an N-1 criterion in localities in which a cost benefit to the community is not prevalent;
- Aurora is required to undertake a 10 year demand and consumption forecasting exercise for the distribution network.

5.4. New South Wales

5.4.1. Electricity Supply Act 1995

The Electricity Supply Act 1995 is the primary legislation covering the obligations and performance of the DNSPs in NSW (EnergyAustralia, Integral Energy and Country Energy). In August 2005 the then Minister for Energy imposed additional conditions relating to reliability performance on licences held by distribution network service providers under the Electricity supply Act 1995.

5.4.2. Design, Reliability & Performance License Conditions

The Department of Energy, Utility and Sustainability has imposed new planning standards under the Design, Reliability and Performance Licence Conditions for Distribution Network Service Providers, effective 1 December 2007 (Schedule 1) Design Planning Criteria. These new planning criteria are summarised, along with those applicable to other DNSPs in Appendix A of this report.

The notable highlights of Schedule 1 and the full Licence Conditions are:

- The NSW criteria are essentially "deterministic" in nature with the potential to apply some probabilistic or energy at risk discretion provided by Note 1 to the schedule;
- Increased system security (N-2 equivalent) down to zone substation level in the CBD of Sydney;
- Different levels of "threshold" loads to be secured by N-1 security for EnergyAustralia (10 MVA), Integral (15 MVA until 2014) and Country Energy (15 MVA), in urban and rural areas;
- An underlying principle of securing loads above 10 or 15 MVA with N-1 security;
- Criteria specified are "minimum standards" for various categories of network elements;
- A licence holder must be "as compliant as reasonably practicable in relation to all network elements by 1 July 2014;
- A licence holder must be "fully compliant by 1 July 2019".

5.4.3. Definition of a Credible Contingency

N-1 is the general industry terminology given to describe the conditions under which all (or a certain percentage) of the electricity load will continue to be supplied under conditions whereby a critical system element is out of service (i.e. N is with the system intact and N-1 is with one element (normally the one of the highest capacity) out of service). N-1 is also referred to as a credible contingency. That is to say some outages may be considered "non-credible" contingencies. As an example in NSW the coincident failure of TransGrid's 330 kV circuits 41 and 42, supplying Haymarket and the CBD is not considered a credible contingency for system planning purposes while the loss of one of these circuits (41 or 42) and one of EnergyAustralia's 132 kV feeders in that part of the network is considered a credible contingency.

The adoption of the new design planning standards in NSW has caused at least some of the utilities to reconsider what are deemed to be credible contingencies in defining N-1 particularly as it relates to:

- Failure of a tower on a double circuit 132 kV overhead line;
- Multiple transmission and sub transmission cables in a common trench;
- Failure of a 132 kV bus-bar;
- Failure of an 11 kV bus-bar;
- Total loss of a zone substation;
- Loss of multiple distribution (11 / 22 kV) feeders in a pit and duct system.

5.4.4. Demand Management Code of Practice

The Electricity Supply Act 1995 requires that licence conditions imposed on the DNSPs require them to conduct and publish the results of investigations into the cost effectiveness of implementing DM strategies as an alternative to network based augmentation.

The Demand Management Code of Practise provides guidelines to the DNSPs on how to meet the licence obligation in regard to DM.

The attached figure provides a detailed flowchart of the procedures to be followed under the NSW Demand Management Code of Practice.

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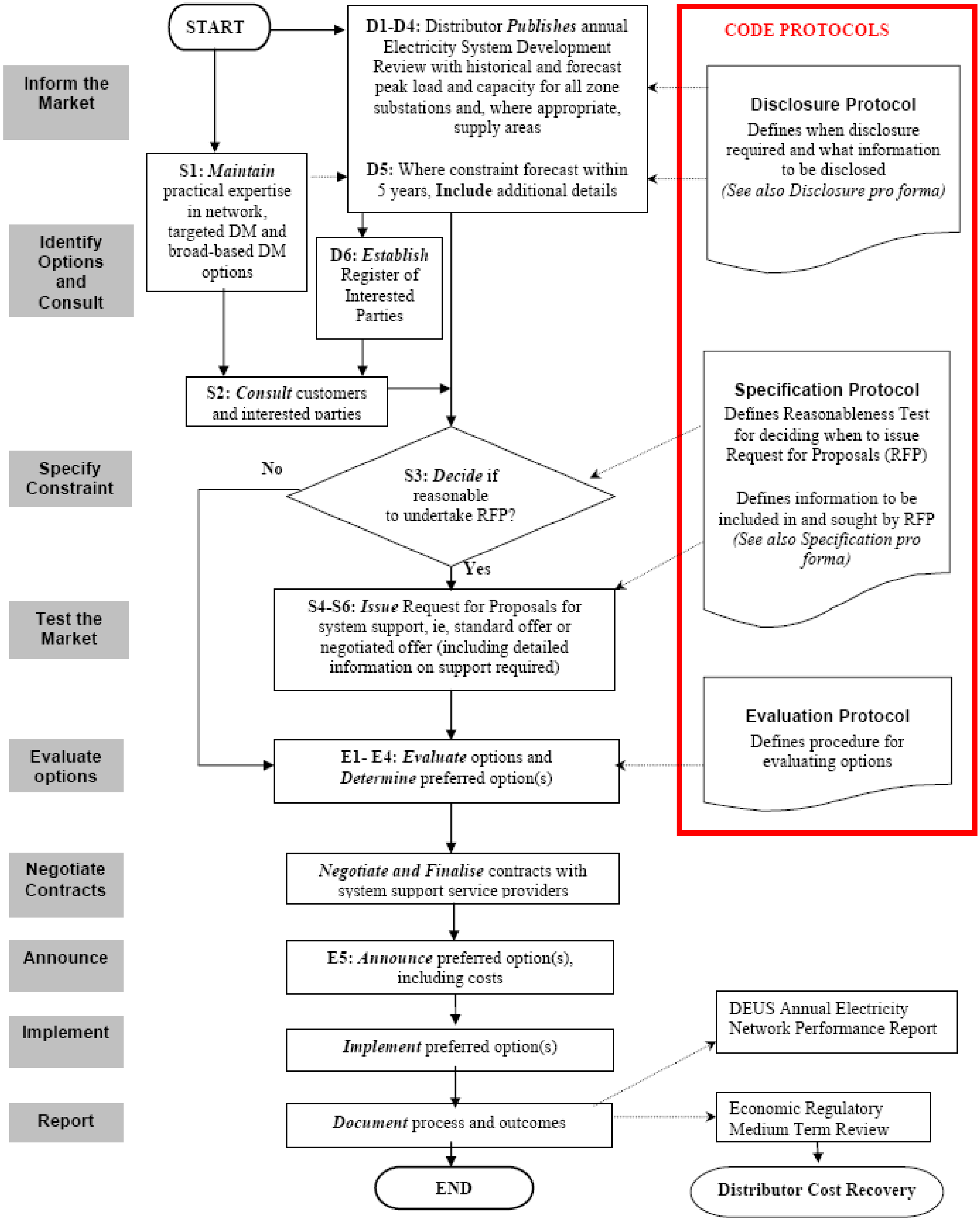
Figure 2 Electricity system development procedure for distributors



Source: Demand Management for Electricity Distributors, NSW Code of Practice, September 2004.

The DM Code of Practise requires that DNSPs:

- Keep a register of interested parties that wished to be informed of DM opportunities;
- Issue a formal Request For Proposal (RFP) calling for non-network solutions to specific network constraints where the total annualised cost is likely to be greater than $200,000;
- Annually produce an Electricity System Development Review (ESDR) as part of its NMP;
- Evaluate and rank all proposals (network and non-network) on the basis of the total annualised cost of providing the system support.

IPART requires an independent external audit of each DNSPs DM projects and programs before agreeing to their D factor submissions.

5.4.5. Electricity Supply Regulations 2001 & 2002

DNSPs are required under the Electrical Supply (Safety and Network Management) Regulations 2002, to submit a NMP.

5.5. Australian Capital Territory

5.5.1. Utilities Act 2000

The Utilities Act, 2000 is the primary legislation covering the responsibilities and performance of ActewAGL, the sole electricity distribution in the ACT. The Utilities Act, 2000, provides for the network service provider to own, operate and maintain an electricity distribution system in the ACT and makes certain provisions / obligations in the areas of:

- Requirements for holding a Utility Service Licence;
- Duties of an Electricity Distributor;
- Compliance with the Electricity Code and Metering Code;
- Powers of a licence holder;
- Development of individual and overall performance standards;
- Enforcement of obligations;
- Electricity supply from renewable resources.

Overall however, the Utilities Act, 2000 does not place any specific obligations on the licence holder as to how they will conduct their network planning activities, develop planning criteria, establish network performance targets nor how to communicate these in an open and transparent manner.

5.5.2. Electricity Distribution (Supply Standards) Code

The Electricity Distribution (Supply Standards) Code dated December 2000 includes specific requirements for quality and reliability of supply, including issues such as:

- Nominal voltage;
- Rapid fluctuations in supply voltage;
- Voltage dips;
- Switching transients;
- Voltage differences (neutral to earth);
- Earth potential rises;
- Voltage unbalance;
- Direct currents;
- Harmonics of voltage and current waveforms;
- Lightning protection;
- Reliability targets (SAIDI / SAIFI);
- Levels of supply capacity to contracted customers;
- Levels of electromagnetic fields (EMF).

The code requires that an annual report must be prepared and submitted to the Chief Executive of the Electricity Distributor, but does not require that it be published.

5.5.3. New Service Standard Requirement – ACT Government (2006)

In 2006 the ACT Government created a statutory network performance requirement (Network Service Criteria) that applies to TransGrid. The criterion requires that TransGrid, by 1 July 2009, establish a second supply point in the ACT with a capacity of at least 375 MVA. Utilisation of the supply point capacity will require ActewAGL to develop and connect 132 kV lines to the supply point. The Network Service Criteria has additional obligations which TransGrid must meet by 1 July 2012.

5.5.4. Other Regulatory Acts and Obligations

There are a number of other regulatory acts and documents which comprise obligations on the electricity distribution in the ACT, including:

- Electricity Network Use of System Code (2000);
- Utilities (Network Facilities) Tax Act (2006);
- Territory-owned Corporation Act (1990);

- Consumer Protection Code;
- Ring-fencing Guidelines;
- Management of Electricity Networks Asset Code;
- Utilities Act (2000); and
- Other.

None of these regulatory documents relate specifically to network planning, expansion and reliability of the electricity distribution network.

5.6. Queensland

5.6.1. The Electricity Act

The primary legislation governing the electricity supply industry in QLD is The Electricity Act 1994 and the associated Electricity Regulation. The Electricity Act confers to ENERGEX and Ergon Energy their authority to operate as distribution entities in QLD and defines their areas of supply. The Regulator for the purposes of the Act is the Director-General of the Department of Mines and Energy who is responsible for creating codes and standards and for monitoring compliance with the Act and Regulations, although some of these roles have now been transferred to the QLD Competition Authority (QCA).

5.6.2. Electricity Industry Code

The Electricity Regulation 2006 establishes the QLD Electricity Industry Code (Code) as the approved Code under the Act. The Code prescribes standards relating to network planning, reporting and service standards. Unlike the NSW Licence Conditions, the QLD Code does not define Security of Supply Criteria. The Minimum Service Standards (MSS) specified in the Code are written in output measures of reliability performance rather than input planning criteria. The MSS sets SAIDI and SAIFI performance targets out to 2014/15.

The Code establishes a requirement for each distribution entity to publish an annual NMP and a Summer Preparedness Plan. This latter plan is more an operational plan to mitigate the risk of supply outages during the summer storm period than a network augmentation or expansion plan. The annual NMP is required to detail how each entity "will manage and develop its supply network with the objective of delivering an adequate economic, reliable and safe connection and supply of electricity"[1]. Amongst other information, the contents of the NMP should include:

- Growth forecasts;

[1] Section 2.3.1, Electricity Industry Code, Fourth Edition, DME, July 2008

- Planning policy and an assessment of compliance with policy;
- DM strategy including programs and opportunities for demand side participation;
- Risk assessment of major constraints in the network and how they will be relieved; and
- Consideration of reliability performance.

5.6.3. EDSD Review

In March 2004, in response to concerns regarding network performance over the summer storm period, the QLD Government established an independent panel to review QLD's electricity distribution industry. The Panel provided a detailed report to Government entitled, EDSD. The report contained 42 recommendations and it is from these recommendations that the QLD Distributors have developed the security of supply criteria used in their network planning. The security of supply criteria in force in QLD is not a condition of licence but result from a commitment from the distributors to the shareholding minister to adopt the recommendations of the EDSD report.

ENERGEX and Ergon Energy have adopted deterministic security of supply criteria which specify thresholds of load for various levels of the network. These demand thresholds establish where security levels of N, N-1 and N-2 should apply. The Security of Supply criteria are presented in detail in Appendix A of this report. The previous criteria in use in QLD allowed a more probabilistic approach to security. It was commonly referred to as Reliability Assessment Planning (RAP). Although the deterministic criteria have been adopted for network planning, the QLD networks are not yet fully compliant with the new criteria and are unlikely to meet full compliance within the next regulatory period. The defined security criteria contain several varieties of the traditional N-1 criteria. These variations allow for some load to be lost under first and second contingency conditions, as long as supply can be restored within nominated timeframes using remote or manual switching.

6. Jurisdictional Distribution Reliability & QoS Standards

6.1. South Australia

6.1.1. Reliability Standards

In SA, the SAEDC sets targets for SAIDI, SAIFI and CAIDI in accordance to geographical areas. These targets are summarised in the table below:

SAIDI and SAIFI Standards

	SAIDI (Average minutes off supply per customer per annum)	SAIFI (Average no. of supply interruptions per customer per annum)
Adelaide Business Area	25	0.30
Major Metropolitan Areas	115	1.40
Barossa/Mid-Nth & Yorke Pen./Riverland/Murrayland	240	2.10
Eastern Hills/Fleurieu Peninsula	350	3.30
Upper North & Eyre Peninsula	370	2.50
South East	330	2.70
Kangaroo Island	450	N/A

Source: South Australian EDC (Dec 2006)

ETSA Utilities is entitled to reliability performance incentive points calculated based on a formula defined in the SAEDC (Schedule 2) for each calendar year. However, it is not clear if this reliability performance incentive points have any impacts on the financial performance of ETSA Utilities.

6.1.2. Quality of Supply Standards

ETSA Utilities is required under to South Australian Electricity Code to comply with the QoS standards such that:

- Voltage is set out in accordance with AS 60038;
- Voltage fluctuations that occur are contained within the limits set out in AS/NZS 61000 Part 3.3 and 3.5 and AS 2279 Part 4;
- Harmonic voltage distortions do not exceed values set out in AS/NZS 61000 and AS 2279, and those set out in the standard connection and supply contract;

- Voltage unbalance factor in 3 phases supplies does not exceed the values set out in the standard connection and supply contract;
- Interference shall be less than the limits set out in AS/NZS 61000 and AS/NZS 2344.

6.2. Victoria

6.2.1. Reliability Standards

The requirements of reliability supply for Victorian DNSPs are specified in section 5 of the EDC published by ESCV.

Specific highlights of these requirements are:

- Before 31 December each year, a DNSP must publish on its website and in a newspaper its targets for reliability of supply for the following year. As a minimum, these targets must include planned and unplanned SAIDI, SAIFI, MAIFI and CAIDI;
- A DNSP must use best endeavours to meet targets required by the Price Determination and targets published under clause 5.1 of EDC and otherwise meet reasonable customer expectations of reliability of supply;
- DNSPs may interrupt supply under the following circumstances:
  - planned maintenance, repair, or augmentation of the distribution system;
  - unplanned maintenance or repair of the distribution system in circumstances where, in the opinion of the DB, the customer's electrical installation or the distribution system poses an immediate threat of injury or material damage to any person, property or the distribution system;
  - to shed energy because the total demand for electricity at the relevant time exceeds the total supply available;
  - as required by NEMMCO, VENCorp or the system operator;
  - the installation of a new supply to another customer;
  - in the case of an emergency; or
  - to restore supply to a customer.

- In the case of an unplanned interruption or an emergency, a DNSP must:
  - within 30 minutes of being advised of the interruption or emergency, or otherwise as soon as practicable, provide, by way of a 24 hour telephone service, information on the nature of the interruption and an estimate of the time when supply will be restored or when reliable information on restoration of supply will be available;

– provide options for customers who call the service to be directly connected to telephone operator if required; and
– use best endeavours to restore the customer's supply as soon as possible making allowance for reasonable priorities.

- In the case of a planned interruption, the DNSP must provide each affected customer with at least four business days written notice of the interruption. The notice must:
  – specify the expected date, time and duration of the interruption; and
  – include a 24 hour telephone number for enquiries.

6.2.2. S-Factor Scheme

In VIC, there is a financial incentive scheme put in place for each DB, whereby their regulated revenue is adjusted through a factor ('S factor') in the price control formula, either upward or downward, depending on their reliability performance. The reliability performance targets are set by ESCV during the Electricity Distribution Price Review (EDPR), which incorporate the annual target levels of SAIDI, SAIFI and MAIFI for each DNSP to comply.

These Reliability Standards are disaggregated into CBD, Urban, Short-rural and Long-rural, depending on the network service area of each DNSPs.

In addition, reliability performance at a customer level is subject to Guaranteed Service Levels (GSL) whereby individual customers who experience reliability levels outside a defined range can receive financial payments.

As set out in the Distribution Licences and the EDC, the DNSPs have the responsibilities to actively engage in the transmission connection planning. Consequently, the supply reliability issues caused by inadequate transmission connection planning are included in the S-factor incentive scheme. Refer more details to the TNSP / DNSP joint planning section under the Victorian jurisdiction.

6.2.3. Quality of Supply Standards

The EDC includes specific requirements for QoS, including issues such as:

- Supply frequency;
- Voltage;
- Pf;
- Harmonics;

- Inductive Interference;
- Negative Sequence Voltage;
- Load Balance;
- Disturbing Loads.

The EDC required each DNSP monitor the QoS in accordance with the principles applicable to good asset management practices as specified in clause 3.1 of the EDC.

6.3. Tasmania

6.3.1. Reliability Standards

In 2008, the TEC was amended by the Regulator to incorporate new distribution network supply reliability standards aligned with the price / service package defined in the Regulator's 2007 price determination.

The new reliability standards are designed to align reliability targets more closely to the needs of the communities served by the network and include a guaranteed service levy scheme supported by the Tasmanian Electricity Code and relevant guidelines.

The new standards are based on the recognition of the value placed on reliability and the impact of supply unreliability upon particular communities. Consequently the reliability targets are more in line with the needs of the communities serviced by the network. There is a guaranteed service levy scheme put in place with the new standards. The new standards are:

Supply reliability category	Average number of interruptions		Average minutes off supply	
	Category frequency limit	Category frequency	Category duration limit	Category duration
Critical Infrastructure	0.20	0.24	30	24
High Density Commercial	1.00	0.55	60	53
Urban and Regional Centres	2.00	1.49	120	207
Higher Density Rural	4.00	3.22	480	485
Lower Density Rural	6.00	3.75	600	605

6.3.2. Quality of Supply Standards

The QoS recognised in TAS generally follows the TEC, the NER and any applicable Australian standards. Specific standards are:

- **Voltage –** TEC requires that the general supply voltage be maintained at 230 volts +10/-6 %;
- **Voltage Fluctuations –** in accordance to section 8.6.4 of the TEC;
- **pf –** All customers are required to maintain their pf in accordance to section 8.6.3 of the TEC.

Also under the distribution licence, Aurora is required to report the following QoS performance indicators:

- Over-voltage events due to high voltage injection events;
- Customer receiving over-voltage due to high voltage injection;
- Over-voltage events due to lightning;
- Customer receiving over-voltage due to lightning;
- Over-voltage events due to voltage regulation or other causes;
- Customer receiving over-voltage due to voltage regulation or other causes.

6.4. New South Wales

6.4.1. Reliability Standards

The reliability standards for DNSPs in NSW are specified in Schedules 2 to 6 of the “Design, Reliability and Performance – DNSP Licence Conditions, dated 1 December 2007. The Licence Conditions also specify the design planning standards referred to in Section 4.4 of this report.

Schedule 2 – Reliability Standards, sets targets for average SAIDI and SAIFI performance over the period 2005/06 to 2010/11, disaggregated into CBD, Urban, Short-rural and Long-rural.

Schedule 3 – Individual Feeder Standards specifies minimum (worst case) targets for SAIDI and SAIFI to apply to individual feeders over the period 2005/06 to 2010/11, disaggregated into CBD, Urban, Short-rural and Long-rural.

Schedule 4 – Excluded Interruptions, defines the types of interruptions that are considered to be excluded events. They include:

- An interruption of a duration of one minute or less;
- An interruption resulting from:
  1) Load shedding due to a shortfall in generation;

2) A direction or other instrument issued under the National Electricity Law, Energy and Utilities Administration Act 1987, the Essential Services Act 1988 or the State Emergency and Rescue Management Act 1989 to interrupt the supply of electricity;
3) Automatic shedding of load under the control of under-frequency relays following the occurrence of a power system under-frequency condition described in the Power System Security and Reliability Standards made under the NER;
4) A failure of the shared transmission system.

- A planned interruption;
- Any interruption to the supply of electricity on a licence holder's distribution system which commences on a major event day, and
- An interruption caused by a customer's electrical installation, or failure of that installation.

Schedule 5 – Customer Service Standards specifies the maximum frequency of occurrence and the maximum interruption duration to be experienced by customers in metropolitan and non-metropolitan areas.

Schedule 6 – Major Event Day defines the process by which the "Beta Method" is applied to identify major event days, which are to be excluded from the reliability standards (Schedule 2) and the individual feeder standards (Schedule 3).

6.4.2. Quality of Supply Standards

Schedule 5.1 of the NER provides a range of network QoS performance requirements however, neither the NSW Electricity Act 1995, nor the Electricity Supply Regulation 2002, nor the Design, Reliability and Performance Licence Conditions for DNSPs define any performance measures or targets that relate to QoS parameters.

As best we can determine, each DNSP has internal policy documentation dealing with supply quality, and each is strongly guided by the requirements of AS/NZS 61000.

We understand that some DNSPs are members of an industry entity known as Australian National Long Term Power Quality Survey (ANLTPQS).

6.5. Australian Capital Territory

6.5.1. Reliability Standards

In addition to meeting the requirements of Schedule 5.1 of the NER, ActewAGL is required to meet the reliability standards set down in the Electricity Distribution (Supply Standards) Code dated December 2000. Section 7.1 Reliability Targets states that:

- An electricity distributor must, before 31 December each year, publish its targets for the reliability of supply for the following year;
- Where groups of customers are expected to receive substantially different levels of service, separate targets should be set under clause 7.2;
- At a minimum, reliability targets should be as advantageous to customers as the reliability targets specified in Schedule 2 to this Code.

Schedule 2 of the Code specifies the following targets for SAIDI / SAIFI / CAIDI:

- SAIDI – 91.0 minutes;
- SAIFI – 1.2;
- CAIDI – 74.6 minutes.

The targets are fixed over time, and the only exclusions appear to be outages of less than one minute, and storm related outages where 10% or more of customers in an area are affected.

6.5.2. Quality of Supply Standards

The Electricity Distribution (Supply Standards) Code also includes specific requirements for QoS, including issues such as:

- Nominal Voltage;
- Rapid Fluctuations in Supply Voltage;
- Voltage Dips;
- Switching Transients;
- Voltage Differences (Neutral to Earth);
- Earth Potential Rises;
- Voltage Unbalance;
- Direct Currents;
- Harmonics of Voltage and Current Waveforms;

- Lightning protection;
- Levels of EMF.

The code specifies certain targets, and refers to Australian Standard 2279.2 or AS/NZS 61000.3.2:1998 where appropriate. The Code also requires that an annual report must be prepared and submitted to the Chief Executive of the Electricity Distributor, but does not require that it be published.

6.6. Queensland

6.6.1. Reliability Standards

In QLD, the Electricity Industry Code sets targets for SAIDI and SAIFI for various feeder categories. These targets are defined as MSS and apply to the average performance across the complete feeder category and are not an indication of the expected performance for any individual feeder.

- **Table 2 Reliability limits**

1 SAIDI Limits								
1.1 ENERGEX								
Feeder type	**2007/8**	**2008/9**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**
CBD	20	20	20	15	15	15	15	15
Urban	134	122	110	105	100	95	90	86
Short rural	244	232	220	215	210	205	200	195

1.2 Ergon Energy								
Feeder type	**2007/8**	**2008/9**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**
CBD	195	180	150	146	142	138	135	132
Urban	550	500	430	419	409	399	389	379
Short rural	1090	1040	980	956	932	909	886	864

2 SAIFI Limits								
2.1 ENERGEX								
Feeder type	**2007/8**	**2008/9**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**
CBD	0.33	0.33	0.33	0.15	0.15	0.15	0.15	0.15
Urban	1.54	1.43	1.32	1.30	1.28	1.26	1.24	1.22
Short rural	2.63	2.56	2.50	2.46	2.42	2.38	2.34	2.30

2.2 Ergon Energy								
Feeder type	**2007/8**	**2008/9**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**
CBD	2.50	2.30	2.00	1.97	1.94	1.91	1.88	1.85
Urban	5.00	4.50	4.00	3.94	3.88	3.82	3.76	3.70
Short rural	8.50	7.80	7.50	7.39	7.28	7.17	7.06	6.95

Notes:

SAIDI Limits, SAIFI Limits shown for 2010/11 to 2014/15 are indicative and subject to change following future reviews of the *minimum service standards.*

Source QLD Government, Electricity Industry Code, Fourth edition: made 31 July 2008; effective 4 August 2008.

When determining performance against these targets, the following interruptions are excluded from consideration:

- Interruptions with duration less than one minute;
- Interruptions resulting from shortfall in generation, transmission failures, NEMMCO directions, automatic load shedding due to under-frequency or directions of police;
- Any interruption that commences on a major event day where a major event day is defined using the Beta Method from ANSI Standard 1366-2003;
- Interruptions caused by a customer's installation.

The MSS are subject to review by the QCA.

Reliability performance at a customer level is subject to GSL whereby individual customers who experience reliability levels outside a defined range can receive financial payments. Amongst other service measures, the Code introduces a "interruption duration GSL" and an "interruption frequency GSL".

The EDSD report introduced the concept of focussing on the worst performing feeders to reduce the variation in performance of individual feeders across each feeder category. Both ENERGEX and Ergon Energy have adopted this "red" feeder strategy.

6.6.2. Quality of Supply Standards

The Code does not define any performance measures that relate to QoS parameters. Similarly, the EDSD was silent in this area. Schedule 5.1 of the NER provides a range of network quality performance requirements to be met by Network Service Providers.

There is an expectation the MSS specified in the Code will be supplemented by QoS standards in the near future.

7. Annual Planning Processes Undertaken by DNSPs (incl. published reports)

7.1. ETSA Utilities

7.1.1. Licence Conditions

As listed previously in Section 5.1, the DNSPs in SA, ETSA Utilities, are required to comply with the requirements of the SAEDC to safe guard the interests of South Australian consumers with regard to price, quality and reliability. Further, ETSA Utilities is required to report annually to ESCOSA on their compliance to these aspects of their licence conditions.

7.1.2. Network Planning Criteria

ETSA Utilities has described its network planning criteria adopted to develop the development plan in the SAEDC section 2.2 with sufficient details.

In general, ETSA Utilities follows deterministic planning approach, where strict N-1 criteria is adopted and applied in particular to CBD area. However, for rural and selected commercial and industrial loads, the N-1 criteria is relaxed and load interruption can occur under N-1 contingency.

Consequently, ETSA Utilities define contingency capacity, with respect to a substation, as N-1 capacity of the substation plus any load which can be transferred to adjacent substations via feeder transfers (excluding those substations where feeder transfers are not to be considered according to ETSA Utilities' planning criteria – e.g. CBD). The typical time (interruption time) to implement feeder transfers is four hours.

With respect to lines, it is defined as the capacity of the network when the first Line becomes overloaded within a region during a contingency condition.

The planning criteria covering the contingency event is detailed in table 2.3 of the SAEDC. For projects to be considered in the capital budget, the following risk level must be identified:

- overload cannot be eliminated by load transfers for Distribution substations and feeders or by Distribution Support Services for Connection Points (requires ElectraNet agreement to latter);
- normal load is above a Distribution Substations' normal rating (tolerance of 0.2 MVA considered);
- normal load is above feeder exit cable's rating;
- normal load is above 33 kV and 66 kV radial lines' rating; and

- voltage at 11 kV bus terminals of online tap changer (OLTC) substations is below 98%, when OLTC at maximum tap (however, a lower voltage is acceptable provided it can be shown that the voltage at each customer's supply point complies with the Distribution Code).

7.1.3. Electricity System Development Plan (ESDP)

ETSA Utilities prepares and publishes annually the ESDP document which provides details of five year substation forecasts, one year feeder load forecasts, and five year sub-transmission line forecasts.

Other information included in the ESDP is:

- Broad description of the load forecast procedure;
- General network planning criteria;
- Network constraints;
- Individual proposed development plan;
- Framework to consider non-network proposals / solutions.

7.1.4. ETSA Utilities Demand Forecasts

ETSA Utilities reviewed its load forecast after each summer peak load period. The review considered the impact of new peak load recorded, system re-configurations, and new large load developments.

Three load forecast scenarios (i.e. high, moderate and low) for all ETSA Utilities' substations and ElectraNet connection points were developed. The moderate forecast is used as the basis for the Electricity System Development Plan, which assume continuation of average demand growth over the past seven years but does not take into account recent or forecast shifts in behaviour.

ETSA Utilities produces:

- Five years substation forecast;
- One year feeder load forecasts; and
- Five year sub-transmission line forecasts.

7.1.5. Process for Consideration of Demand Side Management & Embedded Generation

It appears that ETSA Utilities supports the DM and EG solution to its network constraints that has the potential to reduce peak demand and power flow respectively.

These non-network solutions are being investigated and trialled internally by ETSA Utilities and the details can be found in its website for the latest developments and trial results.

At this stage, there is no evidence that ETSA Utilities has established a proper process to handle the non-network solution proposal.

7.1.6. List of Relevant ETSA Utilities Publications / Reports

Contained within attached Appendix H is a known list of key ETSA Utilities documents and publications relevant to their distribution network planning processes together with SKM's understanding of whether the reports / documents are published for public consumption or not.

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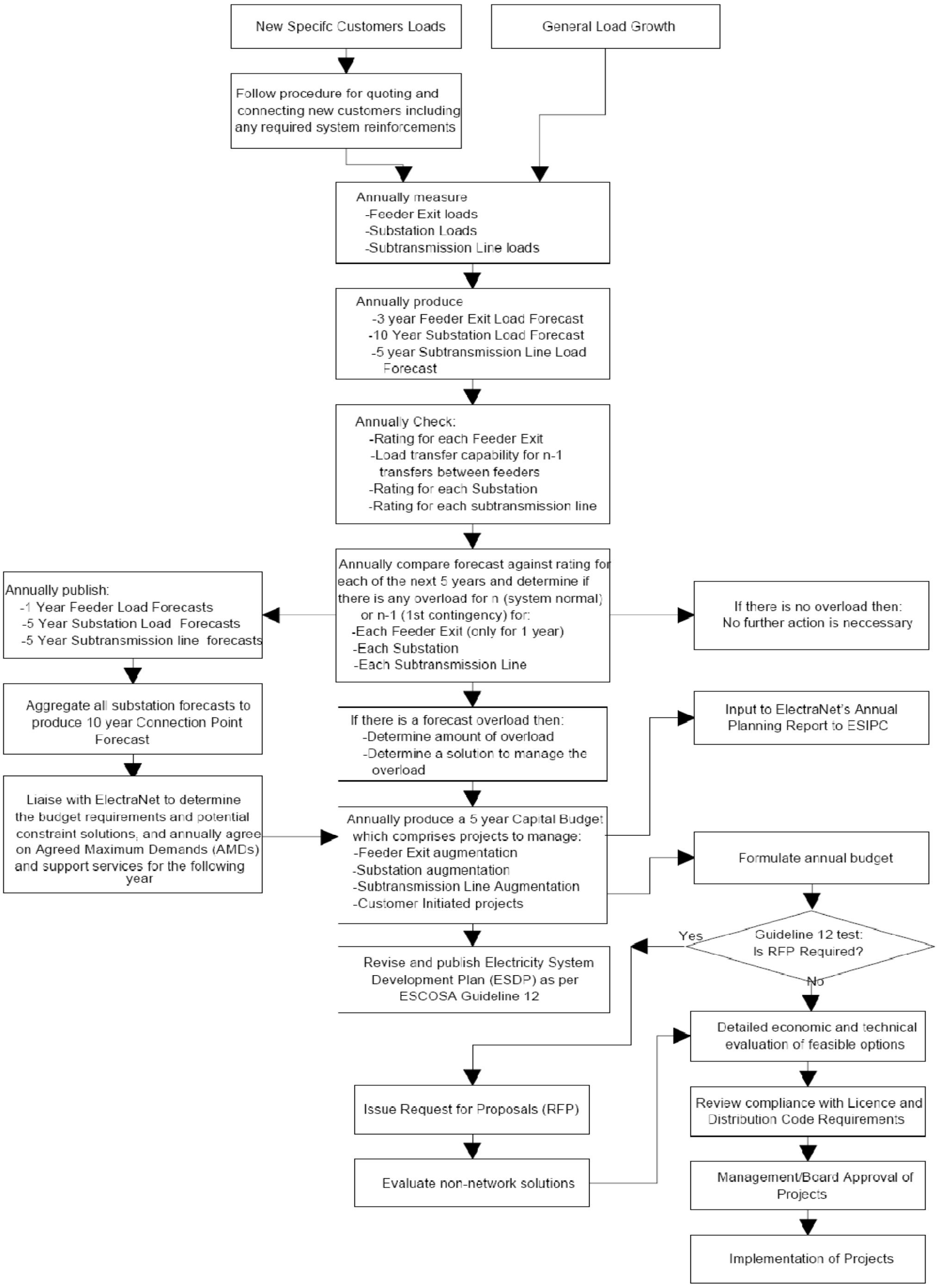
Figure 3 Summary of ETSA Utilities planning and augmentation process



Source: ETSA Utilities – Electricity System Development & Plan, 2008

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7.2. CitiPower / Powercor

CitiPower and Powercor are both owned by CKI (51%) and Spark Infrastructure (49%) and have amalgamated their planning resources. In this context, the two DNSPs can be treated as the same organisation.

7.2.1. Licence Conditions

As listed previously in Section 4.2, the DNSPs in VIC, including CitiPower / Powercor, are required to comply with the requirements of the Design, Reliability and Performance Licence Conditions set out in the Essential Service Commission Act 2001 to safe guard the interests of Victorian consumers with regard to price, quality and reliability. The compliance requirements are specified and administered under the EDC. All Victorian DNSPs are required to comply with the EDC, which sets requirements for quality and reliability of supply both in terms of performance and in terms of monitoring and recording.

Further, CitiPower / Powercor has a licence condition to provide the ESCV with information on quality and reliability of supply, ESCV in turn publishes this information in its website the Annual Comparative Performance Report[2].

7.2.2. Network Planning Process

CitiPower's stated network planning objective is to "achieve a network that is capable of satisfactorily withstanding any single contingency event at the 50th percentile demand forecast without interruption to customers. This N-1 standard provides for the planned or unplanned removal from service of any line, transformer, circuit breaker, etc at the time of 50th percentile MD loading on the station / system, in a manner such that:

- There is no requirement to interrupt customer load;
- Voltage levels on the secondary buses of zone substations are maintained within acceptable Code limits; and
- The loading on all remaining in-service elements is within their operational limits." (see CitiPower's DSPR – December 2008).

The process they use for Distribution Network Planning is shown in the process flow chart shown below:

2 http://www.esc.vic.gov.au/public/Energy/Regulation+and+Compliance/Performance+Reports/

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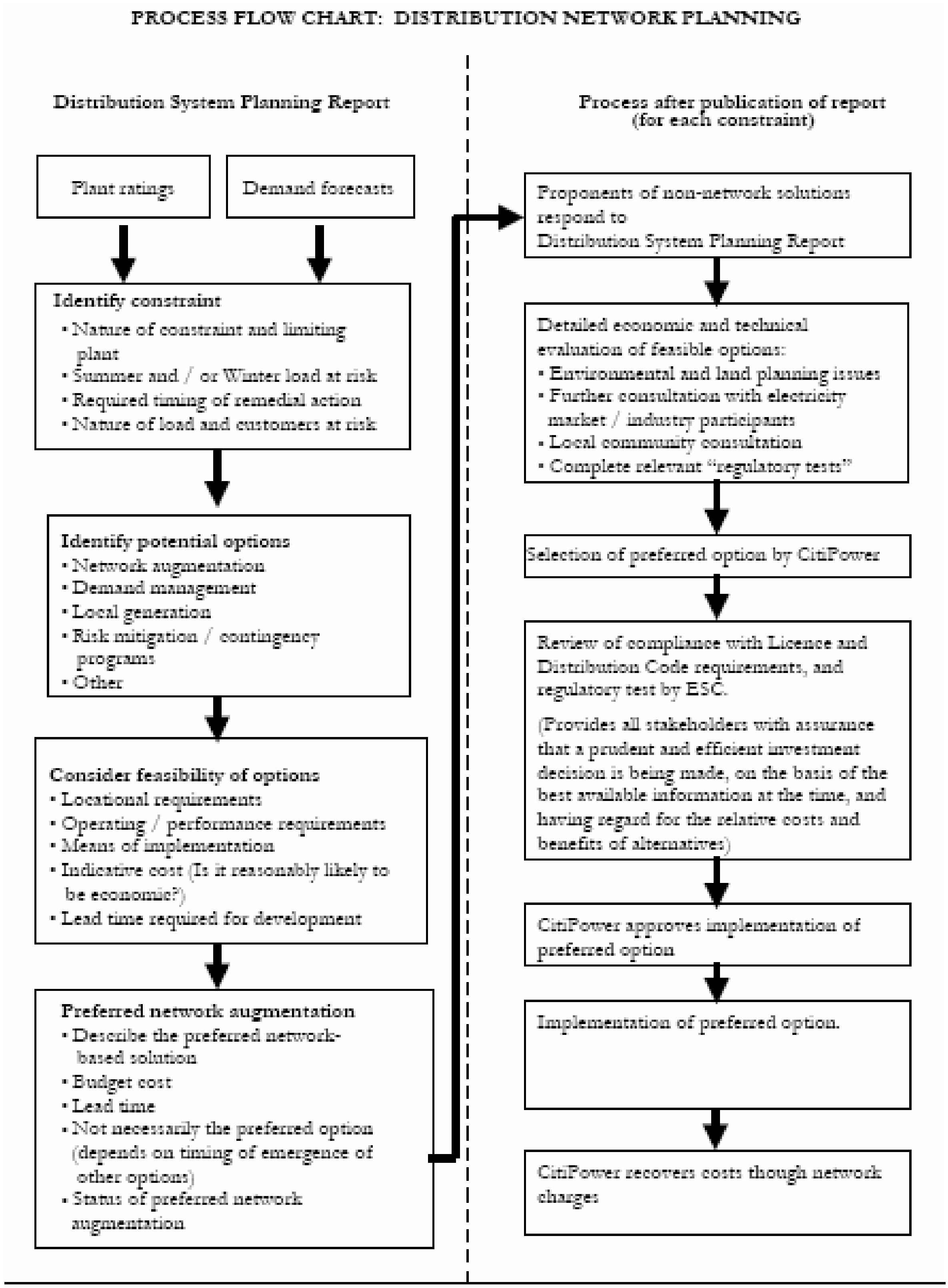
PROCESS FLOW CHART: DISTRIBUTION NETWORK PLANNING
Distribution System Planning Report
Process after publication of report (for each constraint)
Plant ratings
Demand forecasts
Identify constraint
• Nature of constraint and limiting plant
• Summer and / or Winter load at risk
• Required timing of remedial action
• Nature of load and customers at risk
Identify potential options
• Network augmentation
• Demand management
• Local generation
• Risk mitigation / contingency programs
• Other
Consider feasibility of options
• Locational requirements
• Operating / performance requirements
• Means of implementation
• Indicative cost (Is it reasonably likely to be economic?)
• Lead time required for development
Preferred network augmentation
• Describe the preferred network-based solution
• Budget cost
• Lead time
• Not necessarily the preferred option (depends on timing of emergence of other options)
• Status of preferred network augmentation
Proponents of non-network solutions respond to Distribution System Planning Report
Detailed economic and technical evaluation of feasible options:
• Environmental and land planning issues
• Further consultation with electricity market / industry participants
• Local community consultation
• Complete relevant "regulatory tests"
Selection of preferred option by CitiPower
Review of compliance with Licence and Distribution Code requirements, and regulatory test by ESC.
(Provides all stakeholders with assurance that a prudent and efficient investment decision is being made, on the basis of the best available information at the time, and having regard for the relative costs and benefits of alternatives)
CitiPower approves implementation of preferred option
Implementation of preferred option.
CitiPower recovers costs though network charges

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7.2.3. Annual Electricity Network Distribution System Planning Report

CitiPower prepares and publishes annually the DSPR document which provides details of zone substation forecast annual loads out five years into the future. The nature of the information included in the DSPR includes:

- Two years history and five years forecast of summer and winter MDs on a zone substation basis;
- Total substation installed capacity, i.e. N rating (MVA);
- Secure (Firm) substation capacity, i.e. N-1 rating (MVA);
- "Energy at risk' assessments and description of the options available for alleviating constraints for critical zone substations and sub-transmission lines;
- "Hours at risk" assessment for critical zone substations and sub-transmission lines;
- General indication of potential value available to proponents of non-network solutions in deferring or avoiding network augmentation;
- Summary of major zone substation / sub-transmission line projects in the five-year works program, including estimated cost;
- Discussion on Reliability including Reliability outcomes, Reliability Targets and "high level" details of projects in their reliability improvement program.

Section 5 of the DSPR provides a summary of key information about specific locations and substations which will require capacity augmentations over the coming five years, together with the indicative network solutions and, in a few cases, the estimated costs of the indicative solution.

7.2.4. CitiPower's Demand Forecasts

CitiPower's demand forecasting processes include the preparation of:

- Global forecasts at CitiPower's Connection Point level of peak demand and annual energy consumption under 50th percentile and 10th percentile temperature conditions;
- Demand forecasts at the zone substation level are contained in the DSPR and these are weather corrected to the 50th percentile. The forecast consists of a trendline approach coupled with consideration of known and predicted customer connections. The results are compared to National Institute of Economic and Industrial Research (NIEIR) economic forecasts to ensure consistency.

7.2.5. Process for Consideration of Demand Side Management & Embedded Generation

The DSPR and the Joint DNSP TCPR provide the platform for providing information associated with the emerging network constraints to the proponents of non-network solutions (i.e. demand side management or EG).

The DSPR suggests that proponents of non-network solutions to the emerging network constraints (as identified in the DSPR) lodge expressions of interest with CitiPower. Specified details required for submission are listed in section 1.2 of the DSPR. Some highlights of these requirements specified are:

- All non-network proposal must meet applicable Codes and Regulations;
- Any network reinforcement costs required to accommodate the non-network solution will generally be borne by the proponents of the non-network project;
- Provision of financial incentives for connection of non-network solutions – subject to negotiation.

7.2.6. CBD Security of Supply Upgrade Plan

CitiPower has a special requirement under Clause 3.5.3A of the Victorian distribution Code to outline capital and other works associated with the CBD security of supply upgrade plan. These works, along with timing, are detailed for the five year outlook in section 6.1 of the DSPR.

This requirement arose from a CitiPower's submission to the ESCV for extra funding to support an improvement in the security standard for the CBD precinct. CitiPower argued that there was an economic case to improve the CBD security of supply from the existing N-1 criterion to "N-1 Secure". To achieve this outcome requires the installation of additional 66 kV cables, switching of CBD zone substations and the development of external 66 kV ties to provide alternative connection point support. The ESCV approved the submission and allowed CitiPower to fund the works from customer contributions.

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7.2.7. List of Relevant CitiPower Publications / Reports

Contained within attached Appendix H is a known list of key CitiPower documents and publications relevant to their distribution network planning processes together with SKM's understanding of whether the reports / documents are published for public consumption or not.

7.3. Jemena

7.3.1. Licence Conditions

As listed previously in Section 4.2, the DNSPs in VIC, including Jemena, are required to comply with the requirements of the Design, Reliability and Performance Licence Conditions set out in the Essential Service Commission Act 2001 to safe guard the interests of Victorian consumers with regard to price, quality and reliability. The compliance requirements are specified and administered under the EDC. All Victorian DNSPs are required to comply with the EDC, which sets requirements for quality and reliability of supply both in terms of performance and in terms of monitoring and recording.

Further, Jemena has a licence condition to provide the ESCV with information on quality and reliability of supply, ESCV in turn publishes this information in its website the Annual Comparative Performance Report[2].

7.3.2. Network Planning Process

Jemena's network planning process involves four main planning drivers, namely safety, regulatory compliance, load growth, and supply reliability and quality. Forward forecasts of load growth and new customer connections, together with assessments of the loading, condition and performance of existing assets are being considered using these drivers. There are following main stages of the planning process:

- Network Demand Forecasts;
- Identification of Network Inadequacies;
- Technical Feasibility of Options;
- Financial Analysis.

A key output of this planning process is the five-year network strategic plan, which outlines first three years' detailed program of augmentation to ensure network performance is maintained at the required levels.

7.3.3. Annual Electricity Network Distribution System Planning Report

Jemena prepares and publishes annually the DSPR document which provides details of zone substation forecast annual loads out five years into the future. The nature of the information included in the DSPR includes:

- Four years history and five years forecast of summer and winter MDs on a zone substation basis;
- Total substation installed capacity, i.e. N rating (MVA);
- Secure (Firm) substation capacity, i.e. N-1 rating (MVA);
- "Energy at risk' assessments and description of the options available for alleviating constraints for critical zone substations and sub-transmission lines;
- General indication of potential value available to proponents of non-network solutions in deferring or avoiding network augmentation;
- Summary of major zone substation / sub-transmission line projects in the five-year works program, including estimated cost;
- Probability of a major transformer outage (not time adjusted) for the purpose of calculating the value of un-served energy;
- Reliability improvement program.

Section 7 of the DSPR provides a summary of key information about specific locations and substations which will require capacity augments over the coming five years, together with the indicative network solutions and estimated costs of the indicative solution.

7.3.4. Jemena Demand Forecasts

Jemena's demand forecasting processes include the preparation of:

- Global forecasts at Jemena system level of peak demand and annual energy consumption under normal weather conditions, considering 50% probability of occurring;
- Demand forecasts at the zone substation level are contained in the DSPR but it is unclear as to whether these forecasts and the forecasts included in their regulatory submission are weather corrected or not.

7.3.5. Process for Consideration of Demand Side Management & Embedded Generation

It appears that the DSPR is the only platform for providing information associated with the emerging network constraints to the proponents of non-network solutions (i.e. demand side management or EG).

The DSPR suggested proponents of non-network solutions to the emerging network constraints identified in the DSPR are invited to lodge expressions of interest with Jemena. Specified details required for submission are listed in Appendix 5 of the DSPR. Some highlights of these requirements specified are:

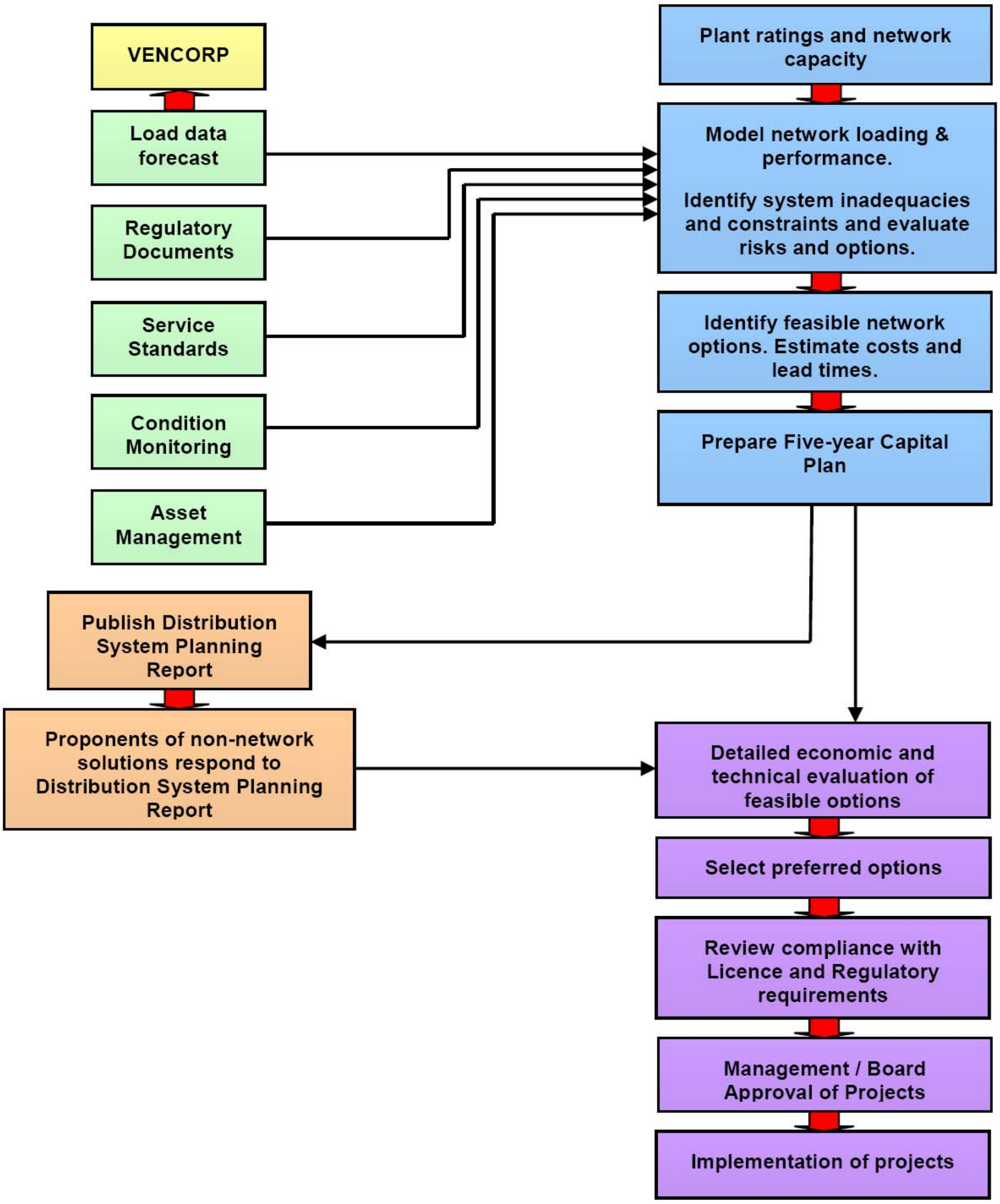
- All non-network proposal must meet applicable Codes and Regulations;
- Any network reinforcement costs required to accommodate the non-network solution will generally be borne by the proponents of the non-network project;
- For non-network solution such as EG, the cost of fault level mitigation works will be borne by the proponents of the non-network project;
- Guidelines for connection of EG published by ESCV.

7.3.6. List of Relevant Jemena Publications / Reports

Contained within attached Appendix H is a known list of key Jemena documents and publications relevant to their distribution network planning processes together with SKM's understanding of whether the reports / documents are published for public consumption or not.

SKM

- **Figure 4 Summary of Jemena's planning and augmentation process**



7.4. SP AusNet

7.4.1. Licence Conditions

As listed previously in Section 4.2, the DNSPs in VIC, including SP AusNet, are required to comply with the Essential Service Commission Act 2001 to safe guard the interests of Victorian consumers with regard to price, quality and reliability. The compliance requirements are specified and administered under the EDC. All Victorian DNSPs are required to comply with the EDC, which sets requirements for quality and reliability of supply both in terms of performance and in terms of monitoring and recording.

Further, all Victorian DNSPs are required to report annually to ESCV on their compliance to these aspects of their licence conditions.

7.4.2. Network Planning Process

Unlike some other Australian States that use deterministic planning (i.e. “N-1”), SP AusNet applies the probabilistic planning approach in its distribution system development. Under the probabilistic planning approach, the amount of energy that is un-served (‘energy at risk’) when one element of the network is out of service is assessed by considering the probability of an unplanned outage of one particular element of the network. The timing of the investment decision is then justified on the basis of when the weighted customer value of un-served energy exceeds the annualised capital cost of augmentation.

The concept aims to provide an optimum level of supply reliability with minimum total cost, by balancing the direct cost of service and the indirect cost of interruption.

SP AusNet has considered distribution losses in its planning and development of distribution assets, which is consistent with EDC’s requirements.

The following are the main stages of the planning process:

- Network Demand Forecasts;
- Identification of Network Inadequacies;
- Carry out ‘Energy at risk’ analysis and calculate expected un-served energy;
- Technical Feasibility of Options for meeting Forecast Demand;
- Financial Analysis.

SP AusNet has established basic statistical data on transformer reliability summarised as follows:

- The major outage rate for transformer is 1.0% (i.e. once per 100 transformer-years);

- Weighted average of major outage duration is 2.6 months;
- Expected transformer unavailability due to a major outage per transformer year is 0.217% (i.e. 0.01x 2.6/12) or 19 hours in a year.

A key output of this planning process is the five-year network strategic plan, which outlines the first three years' detailed program of augmentation, to ensure network performance is maintained at the required levels.

7.4.3. Annual Electricity Network Distribution System Planning Report

- SP AusNet prepares and publishes annually the DSPR document which provides details of zone substation forecast annual loads out five years into the future. The nature of the information included in the DSPR are:
- One year history and five years forecast of summer and winter MDs on a zone substation basis;
- Total substation installed capacity, i.e. N rating (MVA);
- "Energy at risk' assessments and solution identified for alleviating constraints for critical zone substations and sub-transmission lines;
- Summary of major zone substation / sub-transmission line projects in the five-year works program;
- Probability of a major transformer outage (not time adjusted) for the purpose of calculating the value of un-served energy;
- Description of feasible options to meet forecast demand including opportunities for EG and DM.

7.4.4. SP AusNet Demand Forecasts

SP AusNet has advised SKM that the zone substation forecasts are weather corrected by taking into account of the weather condition that produced previous year's MD when preparing the new forecasts. Being also a TNSP, SP AusNet prepare terminal station (Bulk Supply Point) demand forecasts for DNSP load from each terminal station using the zone substation forecasts as input. A 50% PoE and 10% PoE forecast is prepared.

7.4.5. Process for Consideration of Demand Side Management & Embedded Generation

It appears that the DSPR is the only platform for providing information associated with the emerging network constraints to the proponents of non-network solutions (i.e. demand side management or EG).

The DSPR suggested proponents of non-network solutions to the emerging network constraints identified in the DSPR are invited to lodge expressions of interest with SP AusNet Specified details required for submission are listed in Appendix 5 of the DSPR. Some highlights of these requirements specified are:

- All non-network proposals must meet applicable Codes and Regulations;
- Any network reinforcement costs required to accommodate the non-network solution will generally be borne by the proponents of the non-network project;
- For non-network solution such as EG, the cost of fault level mitigation works will be borne by the proponents of the non-network project;
- Guidelines for connection of EG published by ESCV.

7.4.6. List of Relevant SP AusNet Publications / Reports

Contained within attached Appendix H is a known list of key SP AusNet documents and publications relevant to their distribution network planning processes together with SKM's understanding of whether the reports / documents are published for public consumption or not.

7.5. United Energy

As listed previously in Section 4.2, the DNSPs in VIC, including United Energy, are required to comply with the requirements of the Design, Reliability and Performance Licence Conditions set out in the Essential Service Commission Act 2001 to safe guard the interests of Victorian consumers with regard to price, quality and reliability. The compliance requirements are specified and administered under the EDC. All Victorian DNSPs are required to comply with the EDC, which sets requirements for quality and reliability of supply both in terms of performance and in terms of monitoring and recording.

Further, United Energy has a licence condition to provide the ESCV with information on quality and reliability of supply, ESCV in turn publishes this information in its website the Annual Comparative Performance Report[2].

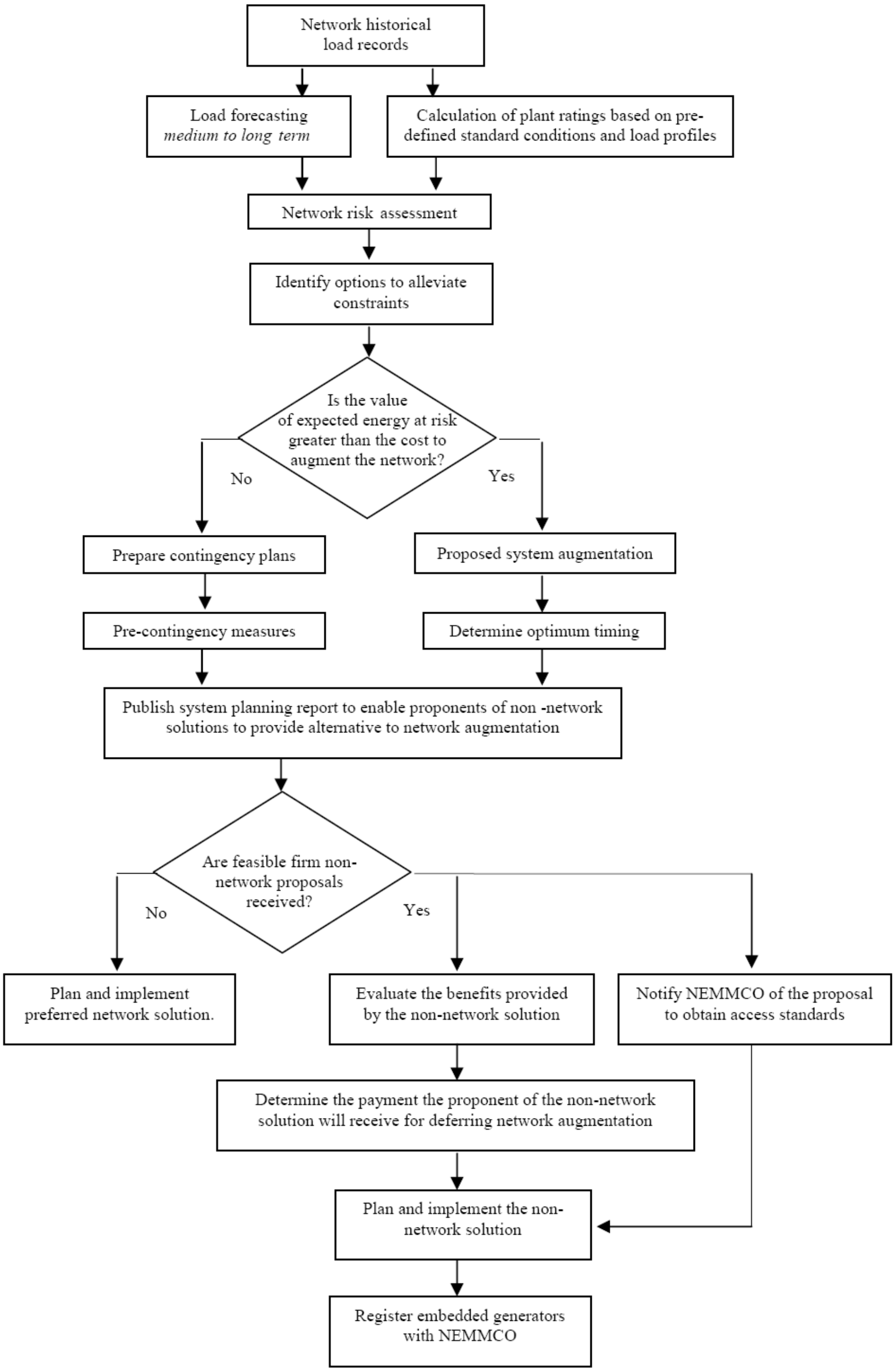
7.5.1. Network Planning Process

United Energy's network planning process involves the following process which is illustrated in detail in the figure below. These are:

- Network Demand Forecasts;
- Identify network constraints / inadequacies;
- Quantify the amount of load at risk;

- Investigate options to relieve constraints, with preferred network solution, its cost, and optimum timing;
- Non-network solutions could identify opportunities based on the DSPR to defer network augmentation and share in the benefits of cost saving.

Figure 5 Summary of United Energy planning and augmentation process



Source: United Energy Distribution System Planning Report 2008

7.5.2. Annual Electricity Network Distribution System Planning Report

United Energy prepares and publishes annually the DSPR document which provides details of zone substation forecast annual loads out five years into the future. The nature of the information included in the DSPR includes:

- Four years history and five years forecast of summer and winter MDs on a zone substation basis;
- Total substation installed capacity, i.e. N rating (MVA);
- Secure (Firm) substation capacity, i.e. N-1 rating (MVA);
- "Energy at risk' assessments and description of the options available for alleviating constraints for critical zone substations and sub-transmission lines
- General indication of potential value available to proponents of non-network solutions in deferring or avoiding network augmentation
- Summary of major zone substation/sub-transmission line projects in the five-year works program, including estimated cost.
- Probability of a major transformer outage (not time adjusted) for the purpose of calculating the value of un-served energy;
- Reliability improvement program

7.5.3. United Energy Demand Forecasts

United Energy used input from NIEIR for forecasting MD, with methodology from regional economic and electricity forecasting models developed by NIEIR.

The observed hotter weather conditions are taken into consideration, where the underlying demand growth may be higher than the true load growth.

A 50% PoE and 10% PoE forecast is prepared.

7.5.4. Process for Consideration of Demand Side Management & Embedded Generation

It appears that the DSPR is the only platform for providing information associated with the emerging network constraints to the proponents of non-network solutions (i.e. demand side management or EG).

In the DSPR, United Energy provided guideline defined by ESCV for the connection of EG to its distribution network, including the ESCV's website where actual guideline document can be downloaded.

The DSPR suggested proponents of non-network solutions to use the DSPR to identify and communicate opportunities where EG or DM system could defer network augmentation. If a 'non-network' solution provides measurable benefits to customers, through either reduced costs or improved reliability, then they may be entitled to a payment. Maximum payment can be obtained if the 'non-network' solution is equivalent to the 'network' solution in terms of both capacity and reliability.

7.5.5. List of Relevant United Energy Publications / Reports

Contained within attached Appendix H is a known list of key United Energy documents and publications relevant to their distribution network planning processes together with SKM's understanding of whether the reports / documents are published for public consumption or not.

7.6. Aurora Energy

7.6.1. Licence Conditions

As listed previously in Section 4.2, Aurora Energy, being the only DNSPs in TAS, is required to comply with the requirements of the TEC to safe guard the interests of Tasmanian consumers with regard to price, quality and reliability. Further, Aurora Energy is required to report annually to OTER on their compliance to these aspects of their licence conditions.

7.6.2. Network Planning Criteria

The Aurora's planning and system development processes is shown in the figure below. It broadly follows these steps:

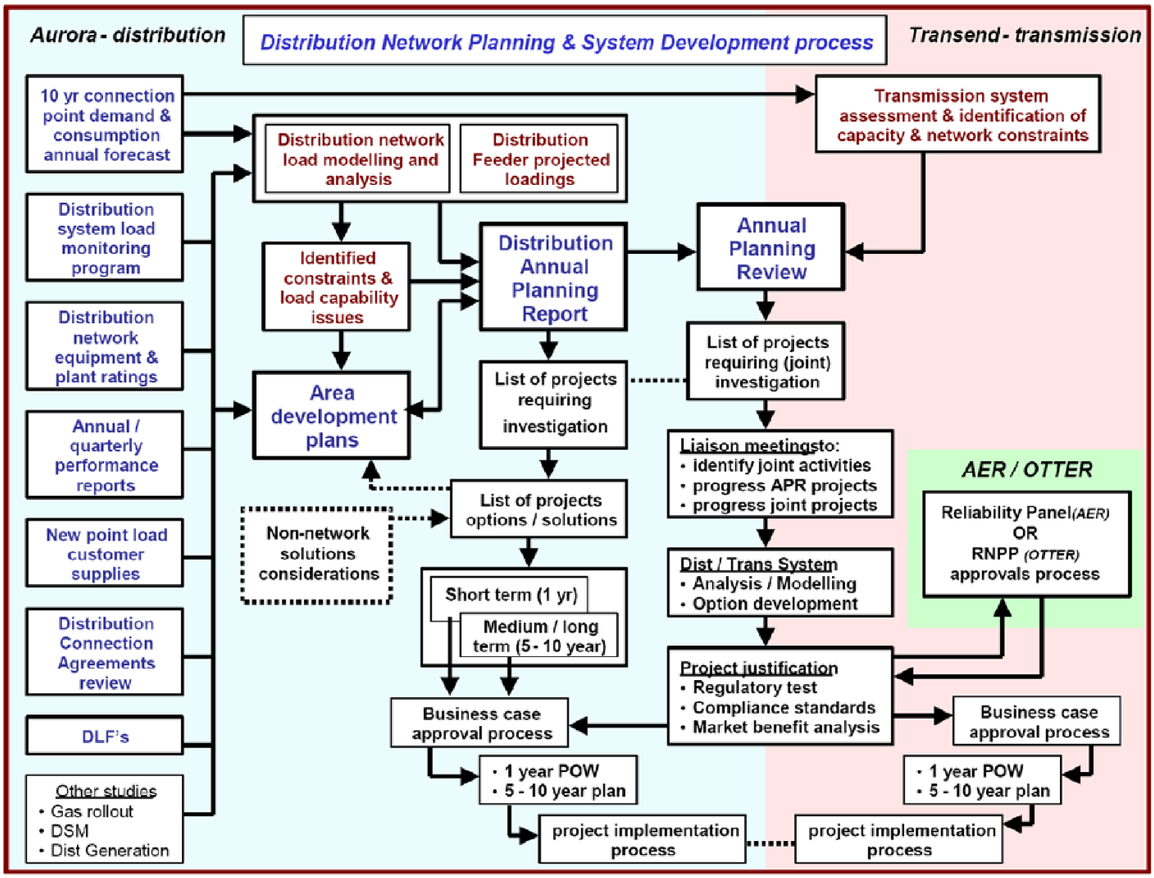
- Identify network constraints and capacity issues;
- Investigate options to eliminate these constraints and to address capacity issue;
- Ensure optimum project timing and costs.

The planning scope of Aurora is impacted by the ownership boundary between Aurora and Transend (the TNSP of TAS). Unlike other Australian DNSPs who are responsible for planning and operating sub-transmission (e.g. 33 kV, 66 kV) and transmission (110 kV, 132 kV), Aurora mainly takes supply from 11 kV and 22 kV bus-bars of the Transend substation.

The Aurora planning approach is mainly deterministic, however this is not apply strictly across its distribution networks for system development. There are instances where N-1 criteria may be relaxed in accordance with the new distribution network supply reliability standards that classify each supply area or community into one of the five supply reliability categories.

Subsequently, Aurora adopted a sub-planning criteria that has some elements of probabilistic approach similar to 'energy at risk' analysis used in VIC DNSPs for its investment evaluation.

- **Figure 6 Summary of Aurora Planning and Augmentation Process**



Source: Aurora Distribution System Planning Report – 2008

7.6.3. Distribution System Planning Report

Aurora prepares and publishes annually the DSPR document which provides details of the network constraints with respect to capacity, security and QoS issues.

The information included in the DSPR is:

- Distribution system load growth;
- Identification of equipment reaching its design and rating limits;
- New customer developments;
- Asset management issues in the retirement and replacement of aged infrastructure;
- Improvement opportunities for feeder reliability performance;

- QoS issues;
- Feasible network options for meeting forecast demand taking into account opportunities for EG and DM.

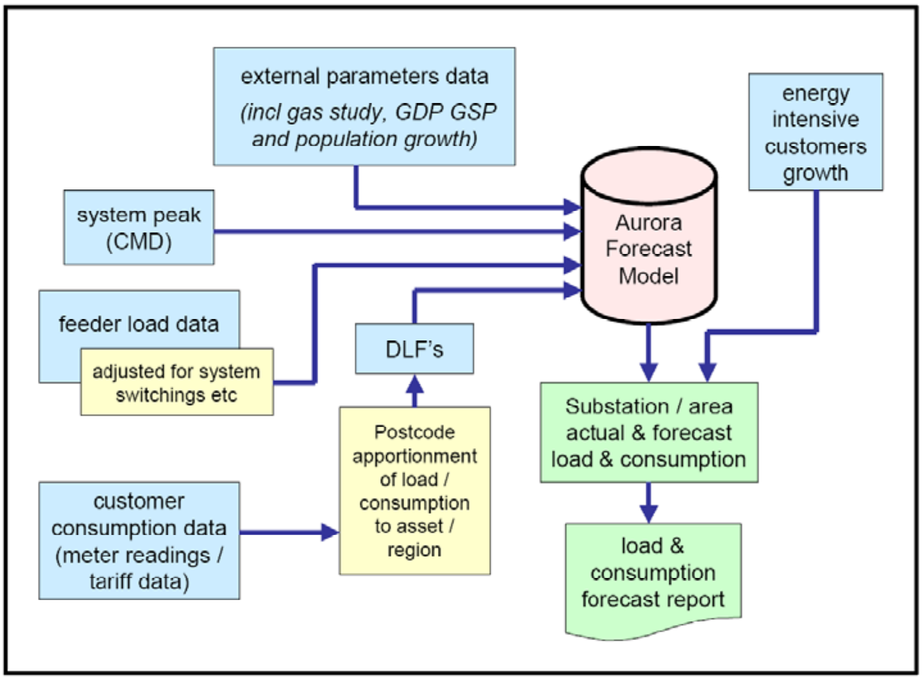
7.6.4. Aurora Demand Forecasts

Aurora has internally developed a load forecasting model which has the ability to take into account any relevant econometric growth drivers. The data inputs for this model are based on energy and demand consumption data collected from customer billing and meter records, allocated by postcodes.

Aurora is required to undertake a 10 year demand and consumption forecasting exercise for the distribution network.

The schematic diagram below show the key components of Aurora's load and consumption forecasting process.

- **Figure 7 Aurora Load Forecasting Process**



Source: Aurora Network Distribution System Planning Report

7.6.5. Process for Consideration of Demand Side Management & Embedded Generation

At this stage, there is no evidence that Aurora has established a proper process to handle the non-network solution proposal. However, Aurora is considering to formulate the impacts of proposed EG into the distribution planning process.

Proponents of non-network solution approach Aurora directly to enquire and to discuss about opportunities in relation to connection and potential infrastructure investment required.

7.6.6. List of Relevant Aurora Publications / Reports

Contained within Appendix H is a known list of key Aurora documents and publications relevant to their distribution network planning processes together with SKM's understanding of whether the reports / documents are published for public consumption or not.

7.7. EnergyAustralia

7.7.1. Licence Conditions – External Audit

As listed previously in Section 5.4, the DNSPs in NSW, including EnergyAustralia are required to comply with the requirements of the Design, Reliability and Performance Licence Conditions for Distribution Network Service Providers, effective from 1 December 2007. Further, EnergyAustralia and the other DNSPs are required to report annually to IPART and the Minister for Energy on their compliance to these aspects of their licence conditions.

This annual compliance report is prepared by an independent external audit consultant.

7.7.2. Network Planning Process

EnergyAustralia's network planning process involves forward forecasts of load growth and new customer connections, together with assessments of the loading, condition and performance of existing assets. This input information is used to develop a range of network development plans, including:

- A range of transmission and sub-transmission area plans (approx 28 in total);
- A 15 year plan for transmission / sub-transmission asset replacement;
- A Reliability Investment Plan for distribution system reliability improvement;
- A Duty of Care Plan to recognise EnergyAustralia's responsibilities under various legislative / regulations requires (e.g. Workplace Health & Safety, Environment, etc.);
- A Customer Connection Plan which provides for the forecast need for new connection assets;

- An 11 kV Capacity Plan which outlines the augmentation requirements to cater for general distribution system load growth as distinct from specific customer connections, or 11 kV works associated with zone substations;
- A Low Voltage Capacity Plan to cater for general low voltage system load growth and facilities load transfers between distribution centres;
- A System and Business Support plan.

These various plans and associated documents are not externally published as a matter of course, but are normally included in EnergyAustralia's five yearly regulatory submission.

7.7.3. Annual Electricity System Development Review

EnergyAustralia prepares and publishes annually the Annual ESDR document which provides details of forecast annual loads out seven years into the future. The nature of the information included in the annual ESDR includes:

- Seven years history and seven year forecast of MDs on a zone and STS basis;
- Total substation installed capacity (MVA);
- Secure (Firm) substation (SC) capacity (MVA);
- Peak substation load (MVA and % of SC);
- Hours pa operating above SC;
- Number of transformers installed;
- pf and the year pf was measured;
- Whether a constraint is reached that will trigger some investment in the next five year.

Appendix 1 of the Annual ESDR provides a summary of key information about specific locations and substations which will require capacity augments over the coming five years, together with the indicative network solutions and estimated costs of the indicative solution.

7.7.4. Regional Network Performance Investment Report

As an outworking of the Annual ESDR information and annual report, EnergyAustralia also produce and publish several annual Regional Network Performance Investment Reports which describe the expected demand growth rates and planned capital investment expenditure on a "region by region" basis. The reports also provide details of "committed projects" and "projects in development". Regional reports are currently available for:

- Sydney CBD;
- Eastern suburbs region;

- Inner city region;
- Sydney South Region;
- Sydney North Region;
- Central Coast Region;
- Hunter Region.

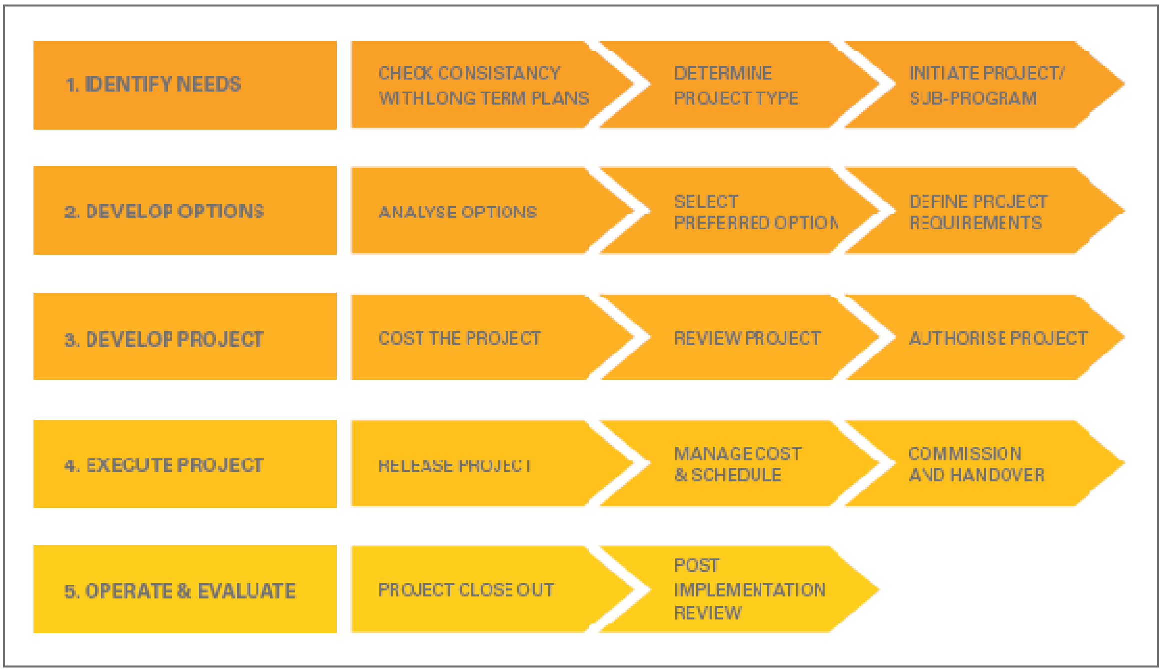
7.7.5. EnergyAustralia's Investment Governance Framework

EnergyAustralia have an over-arching formal capital investment governance framework which is applied for authorization of specific projects and programs of capital. The process is designed to ensure that:

- The need for the capital investment has been demonstrated and authorized at the relevant level;
- The alternatives, including appropriate options have been properly assessed;
- The costs of the proposed solution are efficient and prudent.

EnergyAustralia's Investment Governance Framework process is shown diagrammatically below:

- **Figure 8 Capital governance process**



7.7.6. EnergyAustralia Demand Forecasts

EnergyAustralia's demand forecasting processes include the preparation of:

- Global forecasts at EnergyAustralia system level of peak demand and annual energy consumption under normal weather conditions;
- Spatial demand forecasts at zone substation and STS level which take account of:
  - Historical trends in peak demand growth, both at zone / STS level and system level;
  - Committed increases in new connections and spot load increase;
  - Known load transfers.

- Demand forecasts at the zone and STS levels are contained in the Annual ESDR (see sample below) but it is unclear as to whether these forecasts and the forecasts included in their regulatory submission are weather corrected or not.

SKM

- **Figure 9 EnergyAustralia demand Forecasts Sample extract from Annual ESDR**

System Development Review based on Summer 2006/07 Forecast

Zone Substation Name:	Peakhurst STS
Locality:	Peakhurst
Interconnecting Zone Substations:	N/A
Region:	South
Power Factor at Time of Peak:	0.98
Year PF measured:	2006/07

	Year	Limitation	Total Capacity MVA	Secure Capacity MVA	Peak Load MVA	Load / SC	Hours > SC	Number of Transformers	115% x Load > TC
Actual	99/00				170.7				
	00/01				173.2				
	01/02				193.0				
	02/03				176.3				
	03/04				210.3				
	04/05				214.4				
	05/06				228.8				
	06/07	N-1	380.0	260.0	214.9	83%	N/A	3	
Projected	07/08	N-1	380.0	260.0	232.0	89%	N/A	3	
	08/09	N-1	380.0	260.0	241.2	93%	N/A	3	
	09/10	N-1	380.0	260.0	249.9	96%	N/A	3	
	10/11	N-1	380.0	260.0	258.4	99%	N/A	3	
	11/12	N-1	380.0	260.0	263.5	101%	N/A	3	
	12/13	N-1	380.0	260.0	268.8	103%	N/A	3	
	13/14	N-1	380.0	260.0	274.2	105%	N/A	3	

Is there an investment trigger within 5 years? YES

System Development Review based on Winter 2007 Forecast

Zone Substation Name:	Peakhurst STS
Locality:	Peakhurst
Interconnecting Zone Substations:	N/A
Region:	South
Power Factor at Time of Peak:	1
Year PF measured:	2007

	Year	Limitation	Total Capacity MVA	Secure Capacity MVA	Peak Load MVA	Load / SC	Hours > SC	Number of Transformers	115% x Load > TC
Actual	2000				223.2				
	2001				229.3				
	2002				228.3				
	2003				234.0				
	2004				259.1				
	2005				240.6				
	2006				250.0				
	2007	N-1	375.6	260.0	266.1	102%	N/A	3	
Projected	2008	N-1	375.6	260.0	270.5	104%	N/A	3	
	2009	N-1	375.6	260.0	275.2	106%	N/A	3	
	2010	N-1	375.6	260.0	263.5	101%	N/A	3	
	2011	N-1	375.6	260.0	271.9	105%	N/A	3	
	2012	N-1	375.6	260.0	277.1	107%	N/A	3	
	2013	N-1	375.6	260.0	282.4	109%	N/A	3	
	2014	N-1	375.6	260.0	287.7	111%	N/A	3	

Is there an investment trigger within 5 years? YES

7.7.7. Process for Consideration of Demand Side Management & Embedded Generation

NERA / ACG claimed in their joint report dated August 2007 that "Arguably the distributors in NSW have the most developed procedures for considering alternative non-network solutions.

SKM would tend to endorse this assessment and make the further observation that EnergyAustralia has further attempted to make the process as transparent as possible by dedicating a web page to the explanation of their DM program, including a Program Progress Tracking System which enables proponents (and the general public) to monitor the status of individual DM projects. A sample of the printout of the EnergyAustralia Demand Management Program Progress Tracking web page is shown below.

Location	Reference No	Screening Test	Consultation paper	Investigation report	Project Authorised
Adamstown Zone Substation	NIG11631	17-Jan-08	x	x	x
Baerami & Merriwa	WBS4791	25-Sep-08	x	x	x
Balgowlah Zone Substation	NIG 10272	26-Apr-06	01-June-06	21-Dec-07	x
Bankstown Zone Substation	NIG11192	21-Apr-08	x	x	x
Beacon Hill Zone 11 kV	NIG115446	17-Apr-07	x	x	x
Belrose Zone Augmentation	NIG11630	26-Feb-08	x	x	x

As at 18 March, 2009, the tracker listed a total of 78 DM projects of which seven had progressed beyond the initial screening tests. Under the IPART's 2004 distribution pricing determination there is a "D Factor" adjustment mechanism to the weighted average price cap formula with the intention of neutralising potential regulatory disincentives to Distribution Network Service Providers (DNSPs) implementing cost effective DM measures.

The D Factor contains two adjustments:

- One for the cost of implementing the DM measures (capped at "avoidable distribution costs");
- And the other for the lost revenues associated with the impact of reduced energy volumes under a weighted average price cap regulation formula.

EnergyAustralia have, as required by the IPART determination, had a consultant (SKM) undertake independent audits of the overall methodology and principles of the calculation of both "avoidable distribution costs" and "lost revenues", on an annual basis.

7.7.8. List of Relevant EnergyAustralia Publications / Reports

Contained within Appendix H is a known list of key EnergyAustralia documents and publications relevant to their distribution network planning processes together with SKM's understanding of whether the reports / documents are published for public consumption or not.

7.8. Integral Energy

7.8.1. Licence Conditions

As listed previously on Section 5.4, the DNSPs in NSW including Integral Energy are required to comply with the requirements of the design. Reliability and performance licence conditions for DNSPs effective from 1 December 2007. Further, Integral Energy and the other DNSPs are required to report annually to IPART and the Minister for Energy on their compliance to these aspects of their licence conditions.

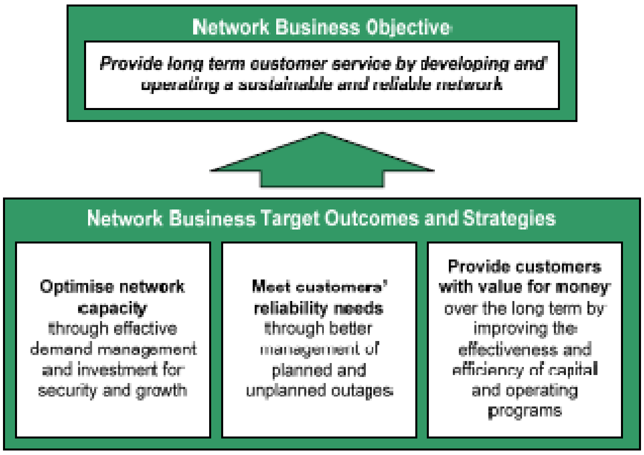
This annual compliance report is prepared by an independent external audit consultant.

7.8.2. IE's Network Strategy

IE's network strategy is to deliver the network business objective to *"provide long term customer service by developing and operating a sustainable and reliable network"*. The three core outcomes of IE's network strategy are in the area of network capacity, customer's reliability needs and value for money.

The IE network strategy model is shown in Figure 10 below:

- **Figure 10 Integral Energy's network strategy**



IE state that their network planning process is highly consultative and transparent with formal network plans being developed annually and the process communicated in the publishing of the Annual Network Planning Statement.

The Annual Network Planning Statement (142 page document) is published on the Integral Energy website, along with a range of other relevant plans / documents, including:

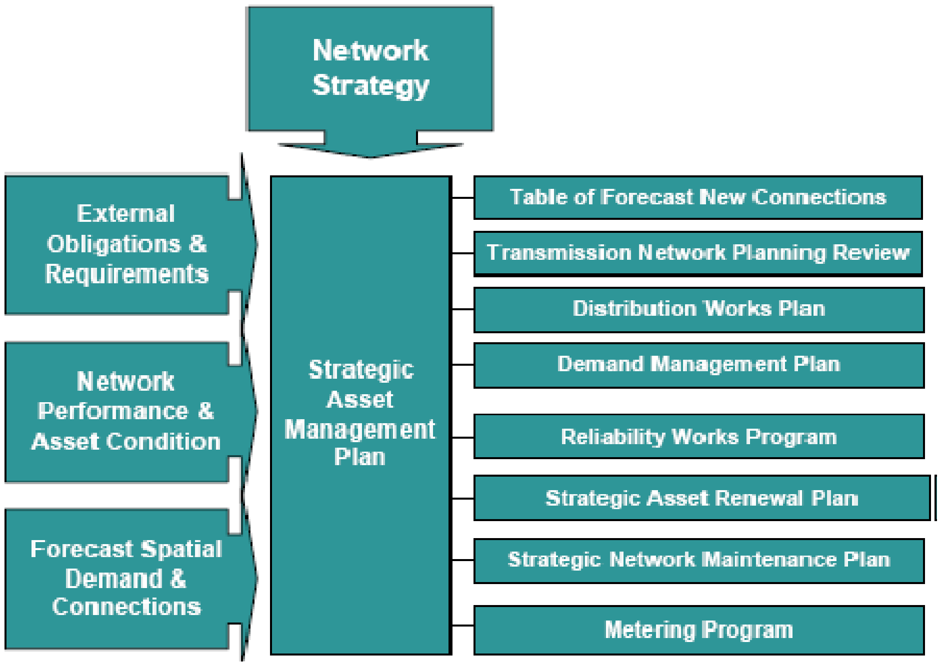
- NMP;
- Bushfire Risk Mitigation Plan;
- Customer Installation Safety Plan;
- Public Electrical Safety Awareness Plan;
- Electricity Network Performance Report;
- Customer Service Standards for Reliability.

As at 27 March 2009 the site also contained NER Consultation Reports for 18 separate augmentation projects, to comply with Clause 5.6.2 of the NEC application of the regulatory test.

7.8.3. Integral Energy's Strategic Network Planning Process

IE's network planning framework is under pinned by the Strategic Asset Management Plan (SAMP), which is in turn supported by a range of input plans, documentation and analysis, as shown in Figure 11 below:

- **Figure 11 Integral Energy's strategic network planning framework**



Each of the boxes down the right hand side of Figure 11 represents a major element of the IE planning process. These documents are referred to in IE's current regulatory submission to AER.

7.8.4. Network Planning Process

Integral Energy plans the expansion and augmentation of its electrical network in accordance with an internal company Policy 9.2.1 – Network Planning. This policy was developed to ensure that IE's planning principals and standards are applied consistently. IE's Network Planning Policy is designed to ensure that:

- Appropriate levels of reliability and QoS are achieved;
- Acceptable levels of asset utilisation are achieved, while not exceeding equipment rating;
- Investment in the network is sufficient to satisfy load growth and is provident within regulatory guidelines;
- Non-network solutions to network constraints are considered where appropriate;
- Risk is managed within the acceptable risk envelope in accordance with the company risk management policy;
- Creditable contingencies are defined during the planning process.

Augmentation decisions are based on a mixture of deterministic and risk-based probabilistic assessments, including the following criteria:

Asset Type	Guidelines
Transmission Lines	When the maximum demand on the line under planning security standard conditions is greater than its maximum rating. The maximum rating of the transmission line is defined as the maximum cyclic rating of the line or cable.
Transmission Substations	When the maximum demand on the substation under planning security standard conditions is greater than its maximum rating. The maximum rating for transmission substations is defined as the cyclic N-1 transformer capacity.
Zone Substations	Augmentation of zone substations will be planned to occur when the load at risk exists for more than 1% of the calendar year. The maximum capacity of the zone substation is defined as the N-1 cyclic rating of the substation transformers or any other constraining element.
Distribution Lines	Augmentation of distribution lines will be planned to occur when the maximum demand on the line under planning security standard conditions (refer Table 2 of the policy) is greater than its design loading level. The design loading level of the distribution line is defined as 80% of the continuous rating of the line or cable.
Distribution Substations	When the maximum demand on the substation under planning security standard conditions is greater than its maximum allowable cyclic rating in accordance with Company Policy 9.2.10 - Network Asset Ratings[6].
Fault Levels	Conductors and primary plant must be capable of carrying through fault current for the duration of the fault, without exceeding their short time rating. Where reclosers are used, the fault duration is the total time for which the circuit breaker is carrying the fault current. Accordingly, augmentation will be planned to occur in order to meet short time ratings of primary plant and conductors. Specific situations shall be referred to the protection specialists for further analysis and confirmation of augmentation required when it is forecast that their fault ratings will be reached or exceeded.

Integral Energy's planning methodology for the transmission network comprises:

- An annual review of the transmission network under summer and winter peak load conditions using the most recent 10 year load growth forecasts;
- Examination of the performance of the network under system normal and single contingency conditions taking into account thermal (current) rating of assets, voltage levels and security of supply. Principle thermal ratings will be the appropriate cyclic rating of power transformers and other constraining elements and 100% of the appropriate cyclic rating of transmission lines and cables;

- A study of the fault levels prevailing in the network in accordance with Company Policy 9.2.10 – Network Asset Ratings;
- Suggested strategies and projects to address all identified areas in the above study where the transmission system does not satisfy this policy. These projects will be subject to individual review and evaluation in accordance with Company Policy 9.2.7 – Network Investing Planning and will be an input into the formulation of the ten year Strategic Asset Management Plan;
- DM options to address network constraints will be evaluated equally with network augmentation options in accordance with Company Policy 9.2.8- DM.

Integral Energy's Planning methodology for the distribution network comprises:

- An annual review of the 11 kV and 22 kV distribution network under summer and winter peak load conditions using the most recent loading information and load growth forecast data;
- Examination of the performance of the network taking into account conductor thermal (current) ratings, voltage regulation, fault with-stand capacity, operational requirements and security of supply where applicable;
- A study using diversified peak load conditions in order to capacity, operational requirements and security of supply where applicable;
- An assessment of the reliability performance of 22 kV and 11 kV distribution network feeders;
- An identification of areas where the environmental performance of the distribution network can be improved;
- A list of suggested projects to address all identified areas where the distribution system may not be in full compliance with this policy. These projects will be am input into the formation of the ten year Strategic Asset Management Plan in accordance with Company Policy 9.2.7 – Network Investment Planning.

7.8.5. Capital Governance within IE

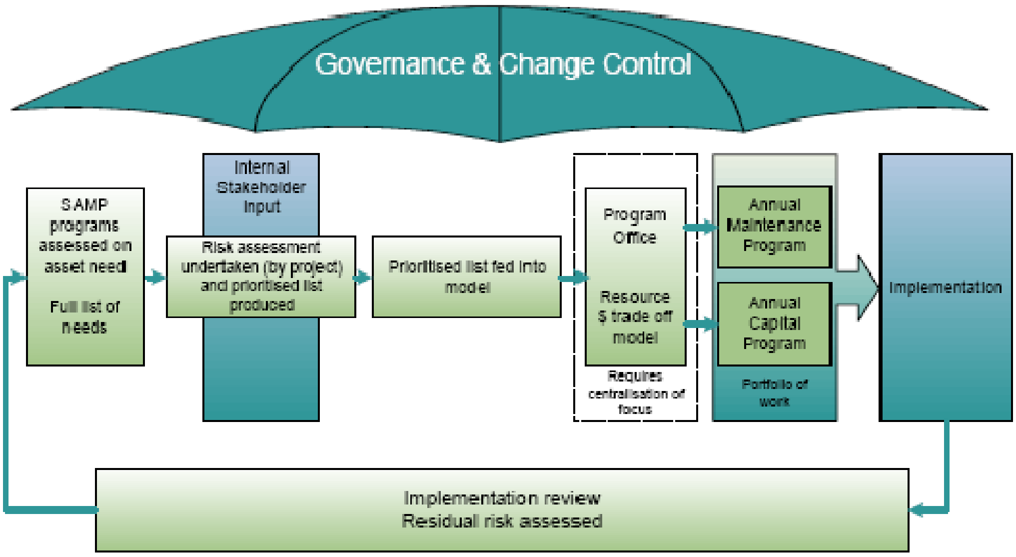
Integral Energy's approach to network planning and asset management is subject to end-to-end oversight by an executive level Capital Governance Committee (CGC), chaired by the Chief Executive Officer. This Committee supports the significant capital program and ensures expenditure is subject to appropriate scrutiny in planning and delivery. The CGC is responsible for selecting an efficient capital portfolio and managing the efficient delivery of that portfolio.

In 2003, the capital governance process was expanded to include major operating expenditure programs for network assets.

Integral Energy's approach to the governance process is illustrated in Figure 12 below.

SKM

▪ **Figure 12 Integral Energy's network asset management model and processes**



The investment planning and risk management processes are integrated within the SAMP to ensure that investment align with the approved corporate risk profile.

The AER's Regulatory Test is applied to all growth driven major projects above $1M and public consultation is undertaken for all projects worth than $10M. The Capital Governance Committee receives post implementation reviews on all capital projects over $1M.

7.8.6. Process for Consideration of Demand Side Management

The following extract from IE's current regulatory submission describing their approach to DM opportunities.

The Demand Management Code of Practice calls for a "Reasonable Test" to be performed for all capital projects to determine if a public process is required for investigating non-network alternatives. Integral performs this test and summarises the results of the test in its annual Network DM Plan. If the reasonableness test concludes that a public process is not warranted Integral may still perform an in-house investigation with specific major customer to identify potential demand reduction. In-house DM investigations are also incorporated into the annual DM plan.

The scope of DM opportunities and initiatives considered by Integral is provided in the SM plan. The plan contains a three year program of investigations and all Registered Interested Parties are notified of all released RFP. This allows interested parties to register their interest in obtaining all information relating to issued RFP's.

The investigation areas included in the 2007/2008 DM Plan are detailed in the two tables below. They include both the public RFP process and the in-house investigation projects.

Table 3 RFP projects and target dates

Project	Year	RFP Issue	RFP Results	Decision
Chipping Norton / Moorebank	2007/08	Sept 2007	May 2008	Jul 2008
Glendenning / Rooty Hill	2008/09	Sept 2008	May 2009	Jul 2009
Huntingwood / Arndell Park	2008/09	Sept 2008	May 2009	Jul 2009
North Blacktown / Marayong	2009/10	Sept 2009	May 2010	Jul 2010

Table 4 Program of investigations for RFP process

Projects for in-house DM Investigation	
Project	Completion Date
Cheriton Ave ZS	June 2008

Planned In-house DM Investigations

The items that have been identified for in-house DM investigation are those that have not passed the 'Reasonableness Test' but may have a possible non-network alternative via one or more customers, generally those responsible for creating the peak demand.

Integral's approach to DM is both embraced in the Network Planning Policy and supported by procedures to integrate DM into the planning processes. This approach includes supporting the contracting of DM opportunities with customers and / or DM providers. The DM Plan ensures that potential DM proponents are provided with sufficient time to undertake their investigations into non-network alternatives and develop detailed submissions.

As a result of the DM plan, Integral publishes Statements of Opportunity and Requests for Proposals for DM in a timely manner for specific system constraints where application of the Code has determined that opportunity may be viable. These documents also provide opportunities for all stakeholders to obtain further information and submit proposals for non-network options.

7.8.7. Embedded Generation

EG growth is steady, with a forecasted need to connect several new generators per annum, for the next five years and beyond. These generators may assist deferral of network capital expenditure. Deregulation of the electricity industry, in concert with increased international desires to reduce greenhouse gas emissions is promoting the increase establishment of embedded and co-generation facilities. Integral is also encouraging embedded and co-generation as a DM initiative.

The existing and possible future use to EG in the electricity network has created the need to review current network planning, network configuration are considered by Integral in its asset management planning.

7.8.8. IE Demand Forecasts

IE's current regulatory submission to the AER provides an overview of their demand and energy forecasting outcomes. During the past regulatory period, IE's average growth in actual MD was 3.4% (2004-2008). Average energy growth over the period was only 1.6% pa, indicating a significant decline in average annual load factor, a trend which is expected to be sustained over the next regulatory period (to 2014).

Integral Energy have confirmed that they produce 50% PoE forecasts at both the system demand level, and also for the transmission and zone substation forecasts that they publish in their ESDR.

7.8.9. Annual Electricity System Development Review (2008)

IE prepares and publishes annually the above document which can be located on their website. The document provides details of forecast annual load out five years into the future, along with a summary of system constraints which will acquire other day solutions to overcome the nature of the information provided included:

- Transmission and associated substations load forecast (summer and winter) out to 2016, together with estimated load at risk (COR);
- A summary of capacity constraints by region and load substation out to 2012;
- Total installed transformer capacity and the resultant cyclic rating (from capacity at each substation);
- Estimated spare capacity / capacity shortages by substation (summer & winter);
- Possible constraints relief projects;
- For substations showing capacity constraints in the next five years, further information is provided on summer and winter load profiles, general load characteristics, possible network solutions and source features of non-network (DM) option.

7.8.10. List of Relevant IE Publication Reports

Contained within Appendix H is a known list of key IE documents and publications relevant to them distribution network planning process, together with SKM's understanding of weather the reports / documents and published for public comparison or not.

7.9. Country Energy

7.9.1. Licence Conditions – External Audit

As listed previously in Section 5.4, the DNSPs in NSW, including Country Energy are required to comply with the requirements of the Design, Reliability and Performance Licence Conditions for Distribution Network Service Providers, effective from 1 December 2007. Further, the DNSPs are required to report annually to IPART and the Minister for Energy on their compliance to these aspects of their licence conditions.

This annual compliance report is prepared by an independent external audit consultant.

7.9.2. Network Planning Process

Country Energy's network planning process involves forward forecasts of load growth and new customer connections, together with assessments of the loading, condition and performance of existing assets. The security criteria of Schedule 1 of their Licence Conditions are key inputs into this analysis. The results of this process are published internally in a series of planning documents.

Area and Regional plans cover specific geographical areas and provide a holistic approach to network development by considering spatial load forecasts, capacity shortfalls, the relevant Design Planning Criteria, asset replacement requirements and network reliability performance. These plans provide the development strategy proposed for the area.

The sub-transmission area planning reports identify existing and forecast network constraints and nominate projects to address these concerns. Subsequently, specific Project Planning Reports are produced providing the detailed project information to deliver the broader strategies outlined in the area plans.

The distribution Regional Centre Plans provide information on current distribution feeder loads, ratings and utilisation levels. They provide a summary of the works planned on the distribution network in the geographical area and generally provide the outcomes in terms of utilisations in the forecast year.

These regional plans are incorporated into the Network Augmentation Management Plan which is part of Country Energy's Network Asset Management Plan. The Network Augmentation Management Plan contains forward projections of loads and customer numbers and identifies network assets that are projected to exceed their limits and proposes development options to address these constraints.

Country Energy's network is geographically very sparse which only allows for minimum levels of extra tie capacity. This tie capacity is taken into consideration when planning new zone substations and STSs.

7.9.3. Annual ESDR

Country Energy prepares and publishes annually the Annual ESDR document which provides a summary of the details contained in the internal planning documents. The nature of the information included in the Annual ESDR includes:

- Seven years history and seven year forecast of MDs on a zone and STS basis;
- Total substation installed capacity (MVA);
- Secure (Firm) substation (SC) capacity (MVA);
- Peak substation load (MVA and % of SC);
- Hours pa operating above SC;
- Number of transformers installed;
- pf and the year pf was measured;
- Whether a constraint is reached that will trigger some investment in the next five year.

This information allows customers and others to consider non-network options that might address foreseen network constraints. Although Country Energy are actively seeking non-network solutions to network issues, it appears that few DM options have been implemented as reliable, economic alternatives to network reinforcement.[3]

7.9.4. Demand Forecasts

Country Energy's spatial demand forecast is fundamentally an extrapolation of historical seasonal demand growth, after adjustment for transfers and spot loads. The STS and zone substation forecasts are not weather corrected. Historical load data is obtained from a number of sources. The load monitoring process is well established utilising system operations records and statistical substation metering where necessary.

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[3] Country Energy's Regulatory Proposal 2009-2014; section 9.4 – June 2008

There are a number of checks to validate the resulting forecast and to increase the level of confidence. One of the methods chosen is to reconcile the summated spatial demands with a separate independent forecast prepared by NIEIR for the entire business based on customer mix, customer growth, appliance penetration and other econometric variables that are used to model NSW economic activity. Although reconciliation of the two approaches can only be approximated, the comparison is used to ensure that similar peaks and trends in growth are reflected in both forecast approaches.

Weather correction of loads has been based on work done by NIEIR at a system demand level, and Country Energy have advised that they use non weather corrected load projections at the zone substation / STS level to conduct its network planning. Country Energy has found that winter loads are relatively less temperature dependent than summer loads and anticipates that this will become a greater issue to them as more of their network moves from winter to summer peaking.

7.9.5. Governance

Investment decisions are subject to a hierarchy of governance bodies and approval authorities. Major projects are incorporated into Country Energy's annual Business Plan, which requires approval of the Board of Directors. Smaller capital investments undertaken by Country Energy are reviewed, approved and implemented by the regional management teams within budgets set in the approved annual business plan. Those with approval authorities are supported and advised by a range of Program Management Offices (PMOs) covering Network Services, Corporate Services etc. The PMOs also track progress of current projects and undertake post implementation reviews.

7.9.6. List of Relevant Publications/Reports

Contained in attached Appendix H is a known list of Country Energy's documents and publications relevant to the distribution network planning processes, together with SKM's understanding of whether the reports / documents are published for public consumption, or not.

7.10. ActewAGL

7.10.1. Statutory Requirements – Network Planning and Reliability

As noted previously in Section 4.5, there are no specific regulatory obligations on ActewAGL to document and publish information regarding their network planning and expansion processes, systems, and objectives. They are however, required to meet certain system wide reliability and QoS targets and report these annually to the Chief Executive.

ActewAGL have advised that detailed reliability statistics are submitted to the ICRC as part of the annual regulatory report, and published within the ICRC compliance and performance reports on their website.

7.10.2. ActewAGL Network Planning Processes

Common with all other DNSPs, ActewAGL's network planning processes commence with the preparation of forward forecasts of customer growth, energy consumption, and demand growth. The unique feature however, of this stage of the process in the ACT is that the release of Crown Land for future residential, commercial and industrial development is actually controlled.

ACT planning and development is the responsibility of two agencies – the National Capital Authority (NCA) and the ACT Planning and Land Authority (ACTPLA). The NCA's role is to manage the Australia Government's continuing interest in the planning, promotion, enhancement and maintenance of Canberra as the nation's capital. The NCA is responsible for the National Capital Plan, which sets out planning principles to be adhered to in the development of the national capital.

ACTPLA is the ACT Government's planning agency. It administers the *Territory Plan* and the supporting codes and planning instruments, and manages the detailed planning and development of the ACT.

The key documents that describe ActewAGL's distribution network planning and asset management framework are:

- The Network 10 year Augmentation Plan;
- The 10 year Customer Initiated Capital Investment Plan;
- The Asset Management Plan;
- The Technology Information Management Strategy; and
- The Metering Asset Management Plan.

These documents contain long term investment and asset management objectives and strategies and cross reference relevant sub-ordinate plans, procedures and standards.

None of the above documents or supporting criteria, procedures or standards are published as a matter of course, but are normally included in ActewAGL's five yearly regulatory submission.

An overview of ActewAGL's distribution network planning and management approach is shown in Figure 13 below.

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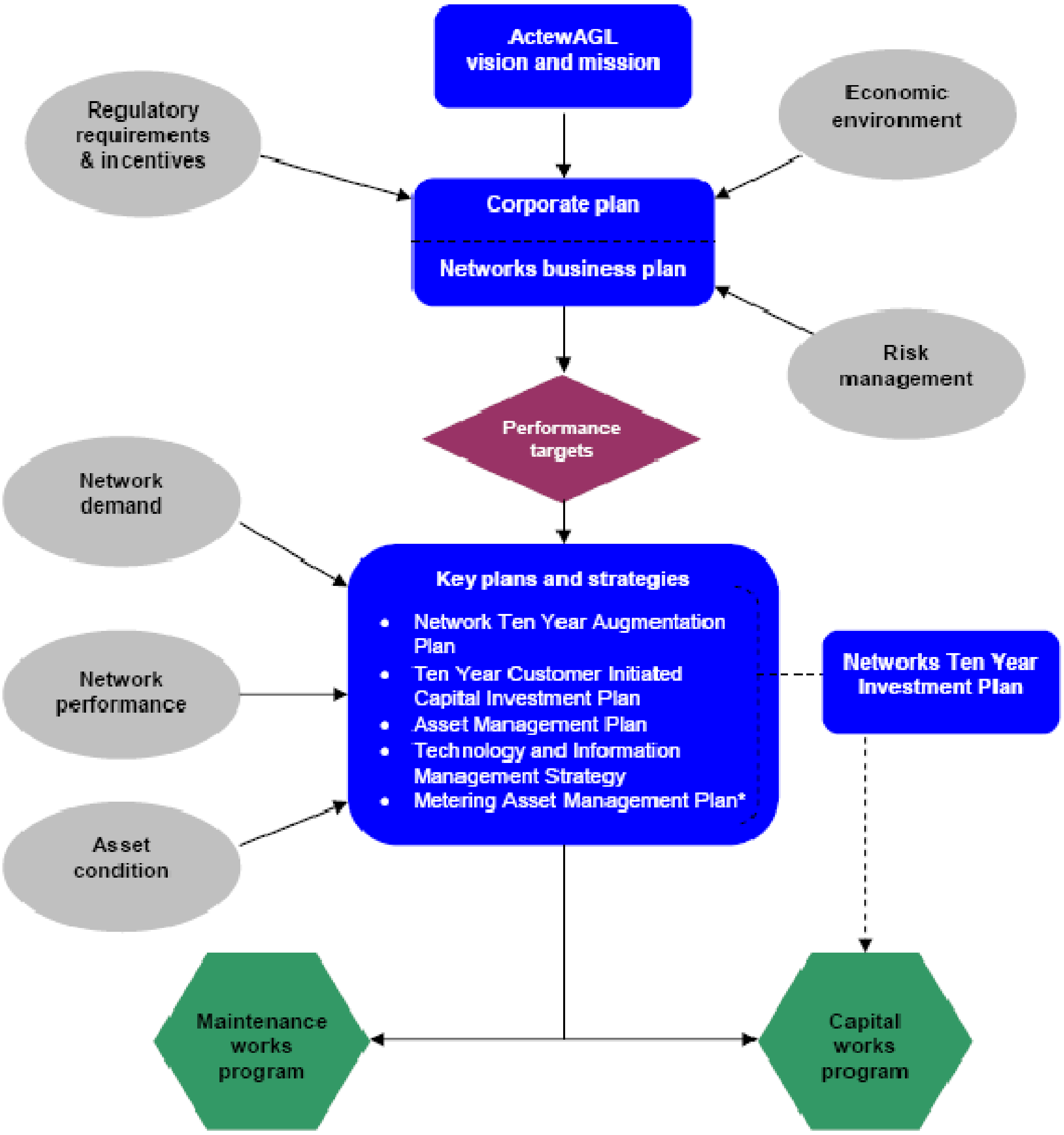
- **Figure 13 Overview of ActewAGL distribution's network planning and management**



7.10.3. ActewAGL

ActewAGL's network augmentation plan is determined using a combination of "deterministic" and "probabilistic" criteria. Deterministic criteria are used to identify areas where system capacity may be exceeded, while a risk assessment is used to determine the priority and timing of augmentation as a result of exceeding the deterministic limits.

The ActewAGL system is typically designed to an N-1 capacity criteria, combined with time based criteria, which allow for the capacity to be exceeded for a limited time.

ActewAGL's network security criteria are shown in Table 5 below:

- **Table 5 Network security criteria for key asset classes**

Asset type	Network security criterion
Sub-transmission lines	The load should not exceed continuous rating of the line for more than 1% of the time; and / or The load should not exceed continuous rating of the line by 20% or more.
Zone substations	The load should not exceed two-hour emergency rating of the substation.
Distribution feeders	The load should not exceed feeder firm capacity* for more than 2% of time; and / or The load should not exceed feeder firm capacity* by 20% or more

* Feeder firm capacity is calculated with a reference to feeder thermal characteristics and network configuration.

7.10.4. Demand Forecasts

There is no regulatory or statutory requirement that requires ActewAGL to prepare or publish annually a demand / energy forecast, either at a total system level or zone sub-station level. ActewAGL do not report this information in their annual report.

As part of its recent regulatory submission (2009-2014), ActewAGL had SKM independently prepare and report on historical and forecast growth in energy consumption and MD. This report is available on the AER website.

SKM's forecasting methodology involved:

- A review of the variation between the 2003 forecasts and actual demand and energy consumption;
- Undertaking temperature / demand correlation to correct historical data for weather variations.
- Removing "one-off" large spot load developments from underlying growth trends;
- An investigation of key drivers of energy consumption in the ACT; and
- The production of system wide energy consumption, system wide demand and zone substation demand forecasts using dynamic econometric and trend modelling techniques.

7.10.5. Demand Management (DM) Initiatives

Historically ActewAGL's approach to DM has been to develop and implement tariff incentive structures, such as time-of-use tariffs. Key tariff and DM measures introduced by ActewAGL include:

- The use of kVA rather than kWh based MD tariffs, which provides incentives for customers with poor pfs to improve their pfs and / or reduce demand;
- Providing stronger demand related price signals by adjusting the balance between the energy and demand component of tariffs;
- Introduction of the capacity tariff;
- Continuing to offer several off-peak tariff options;
- Introduction of time-of-use residential Distribution Use of System charges to complement the mandatory introduction of interval meters in the ACT for all new and replacement installations;
- **Small-scale photovoltaic generation –** ActewAGL has established business processes and tariffs to facilitate the connection of solar energy generation systems to the network;
- **Embedded generation –** ActewAGL has developed technical guidelines and business processes, and ICRC approved standard charges to facilitate customer generator installation and connection;
- **Pf correction –** ActewAGL has amended the requirements of the Service and Installation Rules. Pf correction is a way of controlling or limiting the losses on the network;
- **Network loss management –** the process of planning and design of the network includes network losses as one of the considerations, and is required under the licence conditions.

ActewAGL is not required to, and does not publish the progress with any specific DM initiatives proposed by other parties.

In February 2008, the AER released a Final Decision *Demand management incentive schemes for the ACT and NSW 2009 distribution determinations.* This scheme, known as the "D Factor" scheme, provides an adjustment mechanism to the weighted average price cap formula, with the intention of neutralising potential regulatory disincentives to DNSPs implementing cost effective DM measures.

ActewAGL has included its proposed DM innovation allowance (D Factor) in its current pricing submission.

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7.10.6. List of Relevant ActewAGL Publications / Reports

Contained in attached Appendix H is a known list of ActewAGL documents and publications relevant to the distribution network planning processes, together with SKM's understanding of whether the reports / documents are published for public consumption, or not.

7.11. ENERGEX

As discussed previously in 5.6.2, under QLD's Electricity Industry Code, ENERGEX is obliged to publish annually a NMP. This plan is to include details of the planning process undertaken by ENERGEX and the outcomes of that process.

7.11.1. Network Planning Process

ENERGEX has a well established system planning process and procedure which is documented internally in policy, procedure and strategy documents. The results are published internally in Network Strategic Development Reports, Network Development Plans and project specific reports. In the public domain, ENERGEX's network planning process and results are summarised quite comprehensively for public consumption in the annual NMP. ENERGEX also publishes a range of project reports on the web site for customer notice of work being undertaken and to request community input for some of the larger planned works.

The Network Strategic Development Plan is produced on a three to five year cycle. This strategic plan looks at a longer planning horizon (nominally 20 years) to anticipate the requirement for future substation sites and the possible "ultimate" development of the sub-transmission network in the particular region.

Electricity demand forecasts are discussed in more detail below but are typically prepared for bulk supply and zone substations for a forecast period of ten years. Forecasts are not produced routinely for distribution feeders. Typically as a default the relevant zone substation growth would be applied to the actual feeder loads to provide an indication of when feeder augmentation might be required.

The load forecasts are input into the system models to study the impact of the expected loads on the network and to identify pending constraints. The Network Planning and Supply Manual, including the Security Criteria, statutory requirements (such as supply voltage range) and QoS standards is used to determine when a constraint is met. Network solutions are also modelled to determine technical solutions to overcome identified constraints.

The Network Development Plan is produced for the ENERGEX hubs (regions). This document contains load forecasts, tables comparing forecast loads against asset capacity (and transfer capacity) for substations and feeders and also highlights pending constraints. Solutions are discussed at a higher level.

Specific project planning reports are produced in more detail to analyse and justify recommended augmentation options. Business Cases are produced for project approval providing economic comparison of the alternative solutions identified.

Specific planning reports are published as part of the Regulatory Test requirements under the NER. ENERGEX also routinely publishes planning reports on their web site covering any major augmentation above approximately $1M capital value.

Bulk Supply substation planning is done through joint planning committees in conjunction with the QLD transmission authority, Powerlink QLD.

7.11.2. NMP

The internal planning documents discussed above provide the input to sections of the annual NMP which is a publicly available document. This provides a snap shot of the network expansion plans at the date of compilation. The NMP is supported by a range of other documentation that is not made available publicly.

A requirement of the Code is that the NMP should detail the Distributor’s DM strategy including programs and opportunities for demand side participation. ENERGEX has a number of DM trials in place. They include several area demand reduction programs, load control for residential air-conditioning and distributed generation (in the Kilcoy area). There is no clear indication that ENERGEX actively seeks non-network solutions through public consultation or public issues of requests for such proposals.

For projects over $10M the consultation on appropriate non-network alternatives is done in public as part of the Regulatory Test to ensure the most economically effective outcome is achieved.

7.11.3. Demand Forecasts

Demand forecasts are typically prepared by extrapolating recent historical loads after adjustments have been made for known irregularities such as load transfers, unusual network configurations etc.

ENERGEX has historically weather corrected historical demand records at the broad system level. This relative adjustment has been applied down through the network to the zone substation forecasts. ENERGEX has found that the temperature sensitivity of their area loads is increasing as the penetration of air-conditioning and other temperature sensitive loads has increased.

ENERGEX have confirmed that their load forecasts are weather corrected at the system level, bulk supply substation level, and zone substation level.

ENERGEX recently commissioned ACIL Tasman to review their load forecasting methodology and to recommend improvements that ENERGEX might consider. These recommendations are included in the current ENERGEX NMP. Amongst the adopted recommendations, ENERGEX now includes Gross State Product (GSP) as an input factor (in addition to temperature) in developing their forecast demand relationship at a system level.

ENERGEX are incorporating a DM Strategy in its upcoming Regulatory Submission to the AER. The proposed reduction in demand as a result of DM projects will be incorporated into the forecasts at system, bulk supply and zone substation levels.

7.11.4. Governance

Based on the documentation reviewed to date, SKM has been unable to source any information about ENERGEX's capital governance processes.

7.11.5. List of Relevant Publications / Reports

Contained within attached Appendix H is a known list of ENERGEX documents and publications relevant to the distribution network planning processes, together with SKM's understanding of whether the reports / documents are published for public consumption, or not.

7.12. Ergon Energy

As discussed previously in 5.6.2, under QLD's Electricity Industry Code, Ergon Energy is obliged to publish annually a NMP. This plan includes details of the planning process undertaken by Ergon Energy and the outcomes of that process.

7.12.1. Network Planning Process

Ergon Energy has a well established network planning process which commences with preparation of demand forecasts. The demand forecasts are discussed in more detail below but are typically prepared for bulk supply and zone substations for a forecast period of ten years. Forecasts are not produced routinely for distribution feeders. Typically as a default the relevant zone substation growth would be applied to the actual feeder loads to provide an indication of when feeder augmentation might be required.

The load forecasts are input into the system models to study the impact of the expected loads on the network and to identify pending constraints. The current preferred modelling tool used by Ergon Energy is the DINIS package. The Planning Criteria including the Security Criteria, statutory requirements (such as supply voltage range) and QoS standards are used to determine when a constraint is met. Network solutions are also modelled to determine technical solutions to overcome identified constraints.

Sub-transmission Network Augmentation Plans (SNAPs) are produced for each of the six Ergon regions. These documents contain load forecasts, tables comparing forecast loads against asset capacity for substations and feeders and also highlight pending constraints. Solutions are discussed at a higher level. Specific project planning reports are produced in more detail to analyse and justify recommended augmentation options. Business Cases are produced for project approval providing economic comparison of the alternative solutions identified.

Distribution Network Augmentation Plans (DNAPs) are also produced. These are more often in the form of spreadsheets with a line per distribution feeder providing recent recorded loads, feeder capacity, protection settings etc.

These planning documents are under continual review in an on-going annual planning cycle.

Regional strategic plans are also produced on a three to five year cycle. These strategic plans look at a longer planning horizon to anticipate the requirement for future substation sites and the possible “ultimate” development of the sub-transmission network in the particular region.

Bulk Supply substation planning is done through joint planning committees in conjunction with the QLD transmission authority, Powerlink QLD.

7.12.2. NMP

The internal planning documents discussed above provide the input to sections of the annual NMP which is a publicly available document. This provides a snap shot of the network expansion plans at the date of compilation.

A requirement of the Code is that the NMP should detail the Distributor’s DM strategy including programs and opportunities for demand side participation. In addition to the traditional load control functions, Ergon Energy has a number of DM trials in place. They include several demand reduction programs such as promoting / subsidising ice storage commercial air-conditioning, load control for residential air-conditioning and distributed generation, particularly solar photo-voltaics under the Townsville Solar City project.

For projects that are over $1M, Ergon Energy has in place a system that refers the project to an internal DM team to determine if DM can economically replace or defer the planned project. If analysis shows that DM is preferred the planned project is either deferred or cancelled as required. For projects over $10M the consultation on appropriate non-network alternatives is done in public as part of the Regulatory Test to ensure the most economically effective outcome is achieved.

For individual DM projects, where a specific load or customer is targeted, the forecasts for that particular area (e.g. the relevant zone substation) are modified through a change in block load mechanism that forms part of the inputs to the load forecast. For more widespread DM or energy conservation programs the impact is taken into account as part of the load forecasting process by reducing the rate load growth so that augmentation projects are deferred as necessary until such time as a network constraint actually exists.

7.12.3. Demand Forecasts

Demand forecasts are typically prepared by extrapolating recent historical loads after adjustments have been made for known irregularities such as load transfers, unusual network configurations etc. Future potential major customer loads such as new mines or major expansions are included with a probability weighting based on the forecasters assessment of the probability of the planned new loads proceeding.

A statistical analysis is undertaken of the historical data series to generate forecasts of demands with both 50% and 10% PoE. Generally planning is based on 50 PoE load forecasts where N-1 security is provided. The 10 PoE loads are used for planning in an N security situation, no alternate supply options are available.

For regional loads, co-incidence factors are used to sum connection point loads to a regional total. The average of the coincidence factors over the last 10 years provides the 50% PoE forecasts and the 90th percentile of the same values provides the 10% PoE forecasts. For the Ergon Energy total load a diversity factor is applied to the sum of the regional total forecasts. The average diversity factor for 10 years provides the 50% PoE forecast total load and the 90th percentile diversity factor provides the 10% PoE forecast total load.

None of Ergon Energy's MD forecasts involve correcting any of the historic data for weather normalisation. Ergon Energy believes that weather correction is difficult to apply within their area of supply for several reasons:

- The geographic area covered is extensive and encompasses several climatic areas. If weather correction was attempted there would need to be multiple regional calculations made.

- Much of the Ergon rural load is not temperature dependent. For example irrigation load is increases as rainfall reduces rather than as a function of temperature. However this relationship applies only until water storages are constrained and irrigation is reduced accordingly.
- Previous attempts to correlate Ergon Energy's demand with weather factors has shown poor correlation.

The internally generated demand forecasts are complemented by an econometric forecast commissioned from the consultants, NIEIR. This comparative forecast is a higher level econometric forecast which is mapped into zone substation supply areas. Ergon Energy's process allows for the planning forecast to be adjusted if significant differences are found between the two forecasts.

Note that the Ergon Energy forecasts are also provided to Powerlink for its review and feedback and to support the joint planning process.

Forecasts of customer numbers and energy throughput are not generally undertaken for network planning purposes but are used for network pricing calculations.

A longer term, strategic spatial forecast is also prepared based on current land zonings and the expected final developed load for study area. This is used to produce a long term strategic view of the possible network development ultimately required. Interim development plans can then be prepared consistent with this ultimate view.

7.12.4. Governance

Investment decisions are subject to a hierarchy of governance bodies and approval authorities. The role of the governance bodies is to determine whether an investment should be endorsed or recommended to the decision-making officer.

Network expansion projects are reviewed by the Network Investment Review Committee (NIRC). The purpose of the NIRC is to ensure that the network investment portfolio and the individual components of the portfolio adequately address the needs of the network. The NIRC recommends an investment to General Manager Networks for approval if it is within his delegated authorities.

The GM Networks will take projects that are beyond his authority to the Investment Review Committee (IRC) for consideration. The IRC provides strategic oversight and scrutiny across the full portfolio of competing investments to ensure the business needs are being met. The IRC recommends investments to the Chief Executive for approval if it is within his delegated authority or the Board of Directors as appropriate.

All augmentation projects over $1M are required to undergo a regulatory test, those that are over $10M need to undergo a public regulatory test.

7.12.5. List of Relevant Publications / Reports

Contained within attached Appendix H is a known list of Ergon Energy documents and publications relevant to the distribution network planning processes, together with SKM's understanding of whether the reports / documents are published for public consumption, or not.

8. Assessment of Potential Market Benefits

8.1. Structure of Regulatory Test

The first thing to note about the potential market benefits applicable to distribution augmentation options and projects is that the structure of the existing Regulatory Test is unsuitable for application to distribution networks in its current form. The reason for this is the different definition or meaning that is attached to the word "reliability" in the Reliability Limb. The Regulatory Test, version 3, final Determination, states:

> *"The reliability limb relates the clause 5.6.5A(b)(2) of the NER set out above. It is to be applied to any proposed new network investment or non-network alternative option in the event that the option is necessitated to meet the service standards linked to the technical requirements of schedule 5.1 or in applicable regulatory instruments.*
>
> *While the reliability limb of the test applies to both transmission and distribution network augmentations, in the case of transmission, this limb directly relates to the following definition of reliability augmentation in chapter 10 of the NER. This states that a reliability augmentation is:*
>
>> *A transmission network augmentation that is necessitated principally by inability to meet the minimum network performance requirements set out in schedule 5.1 or in relevant legislation, regulations or any statutory instrument of a participating jurisdiction."*

When one looks at the "reliability" requirements specified in schedule 5.1, they are actually about prescribed security of supply and QoS issues, rather than reliability as delivered to the end customer. The terminology and concepts described in schedule 5.1 are more applicable to transmission systems than distribution systems.

A further problem with the application of the current Regulatory Test to distribution is that if a project qualifies to be treated under the reliability limb of the test, then it is not required to be tested under the market benefits limb. This is at total odds with how distribution augmentation and / or reliability improvement projects are developed, evaluated, and selected for implementation.

When an additional transformer is installed to overcome an N-1 constraint, or a recloser program is developed to improve the reliability of distribution system, the costs of implementing the selected solution are, or should be, tested against the community benefit delivered by the improvement in system reliability. This is the underlying principle of the probabilistic energy at risk modelling used in VIC, and it also underpins the selection of the "hurdle" MD categories used in deterministic planning criteria (refer Section 5.2)

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8.2. Determination of the Value of Customer Reliability

Initially the market based value of lost load (VoLL) was used to value un-served energy. VoLL was increased from $5000 per MWh to $10,000 per MWh in April 2002. Work done by the Monash University in 1997 attempted to recognise the different value that lost load represented to different customer sectors. The results of the Monash study increased the weighted average VoLL to $28,890 per MWh. In 2002 VENcorp commissioned CRA to revise these values. The terminology changed at this time from VoLL to VCR. The CRA project resulted in a state-wide weighted average VCR of $29,600 per MWh[4]. The results of the CRA study are summarised in the table below.

- **Table 6 VCR from Victorian studies**

VENCorp VCR Study (2002)		
Sector	**VCR ($/MWh)**	**Weighting**
Residential	11,867	0.332
Commercial	56,625	0.326
Agricultural	54,782	0.023
Industrial	18,531	0.320
VCR (state average)	29,600	1.000

Both the Monash study and the subsequent CRA work were based on market research to obtain data on the cost impacts of unplanned interruptions on customer sectors.

To date, this approach to assigning a specific community value to un-served energy has only been formally applied in VIC. SKM is of the view that this methodology could provide the basis of a consistent national approach.

8.3. Categories of Distribution Projects

The typical categories of larger capital projects that a DNSP will have in its capital works program, together with examples of the type of project, are as follows:

4 Assessment of the Value of Customer Reliability (VCR), 2002, Charles River & Associates.

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Category	Description	Typical range of projects / program capex	Typical Number per annum
Customer driven	▪ Supply to individual new industrial spot loads (e.g. >5.0 MW)	M$1.0 – M$50	1 – 5
	▪ New overhead or underground residential or commercial estates	K$10 – K$250	10 – 100
	▪ Supply to new / redeveloped high rise buildings	M$1.0 – M$50	1 – 5
Augmentation (capacity driven)	▪ New / augmented zone or sub-transmission substation	M$2.0 – M$50	5 – 15
	▪ New / augmented transmission / sub-transmission feeders	M$2.0 – M$50	5 – 15
	▪ New – augmented primary distribution feeders (11 / 22 kV)	M$0.25 – M$2.0	20 – 50
Replacement / refurbishment	▪ Replace / refurbish zone or sub-transmission substation	M$2.0 – M$50	2 – 10
	▪ Replace / refurbish transmission / sub-transmission feeder	M$2.0 – M$10	1 – 3
	▪ Replace / refurbish multiple types of distribution assets (e.g. poles, conductor, switchgear, etc.)	M$10 – M$50	100's – 1000's
Reliability improvement	▪ Recloser / sectionaliser program	K$50 – K$100 each	10 – 50
	▪ Undergrounding of overhead	K$100 – K$500	1 – 5
	▪ Secondary control and protection system upgrade	K$500 – M$1.0	1 – 2
	▪ New SCADA master station / system upgrade	M$5 – M$10	rarely

The typical numbers per annum of each project type shown above is very approximate only, and would be indicative of a medium to larger DNSP, rather than a smaller one. The number per annum of projects is also representative of the number of larger individually identifiable projects, rather than the hundreds or thousands of smaller distribution projects that a DNSP would typically have in a year.

While we have separated particular projects types into categories (e.g. augmentation, replacement / refurbishment, reliability), in reality a typical large distribution project will have elements of its scope and expenditure which will fall into all of these categories.

As can be seen from the above, the application of a Regulatory Test to projects above a $1M threshold as currently exists could potentially capture primary distribution feeder projects, as well as the majority of reliability improvement projects / programs.

8.4. Replacement / Refurbishment Distribution Projects

The Regulatory Test, version 3 also states that the test is to be applied in relation to new network investments in excess of $1M, and that the Regulatory Test does not apply to the replacement of assets. SKM is of the view that this exclusion should not apply for distribution projects.

Many DNSPs in the NEM have an increasing fleet of ageing and potentially unreliable assets. In some cases it represents up to 30% of their capital budget. Much effort, data collection and analysis goes into determining the optimum timing for the replacement of such assets and there is significant potential for either:

- Premature investment in replacement assets where the probability and consequences of failure do not warrant; or
- Catastrophic failure with widespread customer interruptions when the replacement of critical ageing assets had been deferred for too long.

SKM is if the view that the application of a "market benefit" test is equally applicable to replacement / refurbishment projects, as it is to capacity driven projects or reliability driven projects.

8.5. Types of Costs / Benefits

Appendix A, Regulatory Test, version 3 specifies the types of costs and benefits that may be applied under the "market benefits" limb of the test, and these are repeated below for clarity purposes[5].

> ***"Costs***
>
> 2) *Costs means the present value of the direct costs of an option (or alternative option) including:*
>   a) *Cost incurred in constructing or providing the option;*
>   b) *Operating and maintenance costs over the operating life of the option; and*
>   c) *The cost of complying with laws, regulations and applicable administrative requirements in relation to the option.*

5 Regulatory Test, version 3. Application Guidelines, pp54-55.

Benefits

3) *Market benefit means the present value of the total benefit of an option (or an alternative option) to all those who produce, distribute and consume electricity in the Nations Electricity Market (NEM). That is, the change in consumers' plus producers' surplus or another measure that can be demonstrated to produce an equivalent ranking of options in a majority of reasonable scenarios. For clarity, market benefit does not include the transfer of surplus between consumers and producers, nor does it include the costs defined in paragraph 2.*

4) *In determining the market benefit, the analysis may include the present value of the following benefits:*

    a) *changes in fuel consumption arising through different generation dispatch;*

    b) *changes in voluntary load curtailment;*

    c) *changes in involuntary load shedding using reasonable forecast of the value of electricity to consumers;*

    d) *changes in costs caused through:*

        i. *differences in the timing of new plant;*

        ii. *differences in capital costs;*

        iii. *differences in the operational and maintenance costs; and*

        iv. *differences in the timing of transmission investments;*

    e) *changes in transmission losses;*

    f) *changes in ancillary services costs;*

    g) *competition benefits being net changes in market benefit arising from the impact of the option on participant bidding behaviour; and*

    h) *other benefits that are determined to be relevant to the case concerned.*

5) *Where the analysis separately identifies the magnitude or quantum of any competition benefits (either as a proportion or a component of the total market benefit) the analysis must make clear the methodology used to estimate it.*

6) *The market benefit of an option will only include competition benefits where the network service provider responsible for undertaking the analysis of the option determines that it is appropriate, in all the circumstances, to take competition benefits into account.*

7) *In determining the market benefit, the analysis must not double-count competition benefits where they have already been accounted for in other elements of the market benefit."*

On review, we find that the above definition of costs and benefits are sufficient to cover all of the costs and benefits applicable to distribution networks, with the following proviso's / observations:

1) Item 4(c) be amended to include customer interruptions caused by network outages;
2) Item 4(e) be amended to include distribution losses.

8.6. Cost of Losses

Most, if not all, DNSPs in the NEM attempt to optimise the cost of losses through:

- Specifying and selecting equipment and materials (such as cable, conductors, transformers, etc.) based on economic rating criteria, rather than thermal or technical ratings. This process seeks to minimise total lifecycle costs, including the cost of losses and usually results in larger conductor and cable sizes being selected, than would otherwise be the case. Similarly, transformers with lower losses will usually be favoured over higher loss transformers.
- Undertaking computer load flow studies of their more complex networks to determine how to configure the distribution networks in such a way as to minimise losses, without sacrificing system security or reliability.

There are limits however to the extent to which losses can be reduced economically to a point of optimisation. Most network strategies for reducing losses involve significant capital expenditure, and when capital is constrained, other competing projects often take precedence.

Another characteristic of a capital constrained environment is that utilities are forced to seek to optimise capital expenditure by prudently accepting higher network loadings. This in turn tends to increase system losses, which are of course proportional to the load current squared.

Nevertheless, when different options for an augmentation project present materially different levels of system losses, these should be taken account of under the "market benefit" limb of the Regulatory Test.

8.7. Climate Change and its Impact

The impact of climate change will affect all of the global community in coming years. Businesses that own and manage electricity infrastructure will be required to respond to the changes that occur due to changing weather patterns, changes to regulation and legislation and to community expectations.

As electricity networks are regulated businesses, policy responses by governments and regulators will have a direct bearing on the ability of electricity networks to respond to climate change and deliver a secure and reliable electricity supply in the medium to long term.

Climate change has been forecast to alter long term average and extreme weather, including temperature, rainfall, wind, and storm patterns. Climate is now observed to be changing rapidly in response to human influences, with much of this change occurring outside the bounds of historic variability.

The impacts of climate change will be significant and broad ranging. Commonwealth Scientific & Industrial Research Organization (CSIRO) (2007) has projected some key impacts for Australia. These are summarised in the table below.

- **Table 7 Climate change impacts on Australia**

Climate variable	Change
Temperature	Significant increases in median temperature: 0.7 – 1.2˚C by 2030 0.8 – 2.8˚C by 2050 1.2 – 5.0˚C by 2070 Increase frequency of hot days and warm nights. Decrease in frosts.
Rainfall	Less rainfall overall – more dry days (greater frequency and intensity of drought. Increased intensity of rainfall when it occurs.
Humidity	Decreased relative humidity.
Drought	Increased occurrence of drought over most of Australia.
Wind	Increased average wind speeds. Potentially stronger extreme winds.
Fire weather	Increased fire weather and likelihood of fires.
Sea levels	Higher average sea levels – 18 – 59 cm by 2100. Higher sea level extremes when storm surges combine with higher average sea levels.
Cyclones	Increased number of high intensity cyclones.

In the short term, it is likely that responses to mitigate greenhouse emissions will have a greater impact on network's businesses than actual climate change, particularly as the energy sector will be a key focus of climate change policy.

Climate change presents both risks and opportunities for energy networks. The risks of climate change for energy networks come from two sources:

- The physical impacts of climate change (e.g. extreme weather);
- Regulatory response to climate change (e.g. climate policy).

All other climate related to energy networks including demand risks, supply risks and insurance issues are by-products of physical impacts and human responses.

Energy network companies will be required to manage the physical impacts of climate change. Electricity networks are generally constructed above ground and are designed to cope with extremes of weather, while gas networks are generally built underground. A recent Victorian Government report on climate change impacts on infrastructure found that impacts were likely to be moderate under a low warming scenario to 2070 and moderate to high under high warming scenarios. Network infrastructure in Australia's tropical regions is likely to face the greatest direct physical risks from climate change (Victorian Government, 2007: 39-48).

SKM expects the direct physical impact of climate change is likely to be minimal in the medium term. However robust analysis is required to quantify the timing and size of these risks, and understand them in the context of other impacts. Assets designed and constructed in the next five years will have lives taking them into the period where significant climate change exists, and SKM considers there is a strong case for building mitigation into the design and specification of these assets immediately.

Active management of energy demand will be an important component of the adaptation response. At present it appears to be the most common response. The Electrical Power Research Institute (EPRI) estimates that 1-11% of present demand may be saved though active demand management.

Increased infrastructure damage and network constraints may make it difficult for energy networks to meet their obligations with respect to security and reliability will therefore be a critical adaptation measure. This may drive the move towards more network automation and control systems to improve outage responses.

The extent to which the physical impacts of climate change result in direct costs to business, either through, maintenance and repairs, insurance costs or financial penalties for failing to meet supply obligations will influence companies decision regarding investments in adaptation measures.

The impacts of climate change on others will also affect energy networks.

Demand for electricity will increase in line with rising temperatures and increased use of air conditioning. Increased in peak demand patterns will place pressure on network capacity. Network capacity problems will be compounded by decreased transmission efficiency of power lines during hot weather.

Climate change has been identified as a policy priority by all levels of government. The Australian Government is introducing a number of policy initiatives that will impact on energy networks.

These include:

- The National Greenhouse and Energy Reporting System;
- The Australian Carbon Pollution Reduction (Emissions Trading) Scheme (CPRS);
- The Mandatory Renewable Energy Target (MRET), including recently announced increases in the target to 2020;
- Energy efficiency and demand side management policies.

In the short term, greenhouse abatement policies are likely to have the greatest impact on energy networks. Targeted policies and impacts of emissions trading will drive generation investment into new technologies and locations. Transmission networks will face significant renewable and gas capacity wanting to connect in locations currently poorly serves by existing networks.

This will also affect gas networks, with an increases in expected uptake of gas fuelled generation.

At distribution level, EG and changes in load patterns will impose a significant burden on both electricity and gas networks, particularly for new or upgraded connections.

The issue of losses from both electricity and gas networks is also likely to become a focus of governments at some time, and SKM considers it is important for the networks businesses, governments and regulators to have a common and practical understanding of the potential and costs to reduce losses, as part of the broader least-cost approach to reducing emissions.

9. Dispute Resolution Procedures

SKM has reviewed the Regulatory Test Dispute Resolution Guidelines, November 2007, which have been prepared to help disputing parties understand how the AER will resolve a dispute in relation to applications to establish new large transmission network assets.

We have also reviewed other available documentation from the various State jurisdictions, and have found no reference to a suitable dispute resolution procedure that could be applied to a national framework for distribution network planning and expansion.

We have provided separately to AEMC our thoughts on the general nature of the sorts of disputes that may arise, requiring resolution via an appropriate means.

Appendix A Comparison of System Security & Planning Criteria

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Summary of Standardised Supply Security Criteria

		South Australia			Victoria															
		ETSA			CitiPower			Powercor			Jemena			SP AusNet			United Energy		
Network Element	**Load Type**	**Load Magnitude**	**Security Standard**	**Customer Interruption Time**	**Load Magnitude**	**Security Standard**	**Customer Interruption Time**	**Load Magnitude**	**Security Standard**	**Customer Interruption Time**	**Load Magnitude**	**Security Standard**	**Customer Interruption Time**	**Load Magnitude**	**Security Standard**	**Customer Interruption Time**	**Load Magnitude**	**Security Standard**	**Customer Interruption Time**
Transmission/Sub Transmission Lines	CBD	Any	N-1[1]		ANY	N-1 Transition to N-1 Secure	< 30 minutes (2nd outage)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Urban & Non Urban	Urban [2] ≥10 MVA Urban[3] ≥10 MVA Urban[4] ≥10 MVA	N-1[1] N N		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Urban & Non Urban	Any	N		Any	N-1 but 10% temporary overload allowed	Not Stated	Not Stated	N-1 but 10% temporary overload allowed (dynamic monitoring used)	Not Stated See note 1,2		N-1 but 10% temporary overload allowed			N-1 but 10% temporary overload allowed			N-1 but 10% temporary overload allowed	N-1 but allow 6hrs/line/year or 0.07%
Subtransmission Substation (Bulk Supply)	CBD	Any	N-1[1]		ANY	N-1 probabilistic	Not mandated but will transition to < 30 minutes (2nd outage) under N-1 Secure	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Urban & Non Urban	Any	N-1[1]		ANY	N-1 probabilistic	Not mandated	ANY	N-1 probabilistic	not mandated	ANY	N-1 probabilistic	not mandated	ANY	N-1 probabilistic	not mandated	ANY	N-1 probabilistic	not mandated
Zone Substation	CBD	Any	N-1[1]		ANY	N-1 probabilistic (N-1 with manual load transfers)	< 60 minutes for manual load transfer	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Urban & Non Urban (≥ 10MVA)	Urban [6] ≥10 MVA Urban[8] ≥10 MVA Urban[7] ≥10 MVA	N-1[1] N - (+ feeder transfers) N - 1 plus 10 MVA		ANY	N-1 probabilistic excluding single transformer substations	Not mandated	ANY	N-1 probabilistic excluding single transformer substations	Not mandated	ANY	N-1 probabilistic excluding single transformer substations	Not mandated	ANY	N-1 probabilistic excluding single transformer substations	Not Mandated - Average 19hrs/year for each transformer (or 0.217%)	ANY	N-1 probabilistic excluding single transformer substations	Not mandated Average 11hrs/year for each transformer (or 0.125%)
	Urban & Non Urban (<10MVA)	Peak Load > 6.25 MVA	N-1 plus 5 MVA		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		Peak load < 6.25 MVA	N																
Distribution Feeder	CBD	No info	No info	No info	Not Stated	N-1 (1 spare feeder per bank of 7)	Not mandated	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Urban (town > 15,000)	No info	No info	No info	Not Stated	2 out of 3 Criteria (66%)	Not mandated See Note 5	ANY	2 out of 3 criteria (66%)	Not mandated See Note 5	ANY	2 out of 3 criteria (66%)	Not mandated See Note 5	ANY	2 out of 3 criteria (66%)	Not mandated See Note 5	ANY	2 out of 3 criteria (66%)	Not mandated See Note 5
	Urban (town < 15,000)	No info	No info	No info	Not Stated														
	Non-Urban	No info	No info	No info	N/A	N/A	N/A	ANY	N	Not mandated See Note 5	ANY	N	Not mandated See Note 5	ANY	N	Not mandated See Note 5	ANY	N	Not mandated See Note 5
Distribution Substation	CBD	No info	No info	No info	ANY	N with manual transfers	Not mandated See Note 6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Urban & Non Urban	No info	No info	No info	Not Stated	N with manual transfers	Not mandated See note 6	ANY	N with manual transfers	Not mandated	ANY	N with manual transfers	Not mandated	ANY	N with manual transfers	Not mandated	ANY	N with manual transfers	Not mandated

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Summary of Standardised Supply Security Criteria

		Tasmania			New South Wales & ACT												Queensland					
		Aurora			Energy Australia			Integral Energy			Country Energy			Actew AGL			ENERGEX			Ergon Energy		
Network Element	**Load Type**	**Load Magnitude**	**Security Standard**	**Customer Interruption Time**	**Load Magnitude**	**Security Standard**	**Customer Interruption Time**	**Load Magnitude**	**Security Standard**	**Customer Interruption Time**	**Load Magnitude**	**Security Standard**	**Customer Interruption Time**	**Load Magnitude**	**Security Standard**	**Customer Interruption Time**	**Load Magnitude**	**Security Standard**	**Customer Interruption Time**	**Load Magnitude**	**Security Standard**	**Customer Interruption Time**
Transmission/Sub Transmission Lines	CBD	Transend's assets	Transend's assets	Transend's assets	Any	N-2[6]	Nil for 1st credible contingency <1 hr for 2nd credible contingency	NA	NA		Any	NA		Any			Any	N-2	Nil(1st Outage) Nil (2nd Outage)	Any	NA	See note 1
	Urban & Non Urban	Transend's assets	Transend's assets	Transend's assets	≥ 10 MVA	N-1[1]	< 1 minute	≥ 10 MVA	N-1[1]	< 1 minute	≥ 10 MVA	N-1[1]	< 1 minute	Any			>/=5MVA	N-1[2]	<15min (but typically nil)	>/=15 MVA	N-1[2]	<60 sec (but typically nil)
	Urban & Non Urban	Transend's assets	Transend's assets	Transend's assets	< 10 MVA	N[2]	Best practice repair time	< 10 MVA	N[2]	Best practice repair time	< 10 MVA	N[2]	Best practice repair time	Any			<5MVA	N	Best practise repair but up to 12 hours.	<15 MVA	N	Best practise repair but up to 12 hours
Subtransmission Substation (Bulk Supply)	CBD	Transend's assets	Transend's assets	Transend's assets	Any	N-2[6]	Nil for 1st credible contingency <1 hr for 2nd credible contingency	Any	N-2[6]	Nil for 1st credible contingency <1 hr for 2nd credible contingency	Any	NA		NA			Any	N-1	Nil	Any	NA	
	Urban & Non Urban	Transend's assets	Transend's assets	Not Stated	Any	N-1	< 1 minute	Any	N-1	< 1 minute	Any	N-1[1]	< 1 minute	NA NA			Any	N-1[3]	See notes	>15 MVA <15 MVA	N-1[2] N-1[4]	<60 sec < 3 hours
Zone Substation	CBD	Not Stated	N-1 in general	Not Stated	Any	N-2[6]	Nil for 1st credible contingency <1 hr for 2nd credible contingency	Any	N-2[6]	Nil for 1st credible contingency <1 hr for 2nd credible contingency	Any	NA		Any	N-1[3]		Any	N-1	Nil	Any	NA	
	Urban & Non Urban (≥ 10MVA)	Not Stated	Composite of N-1 & energy at risk	Not Stated	≥ 10 MVA	N-1[1]	< 1 minute	≥ 10 MVA	N-1[1]	< 1 minute	≥ 10 MVA	N-1[1]	< 1 minute	Any	N-1[3, 8]		>/=5MVA	N-1[4]	See notes	>/=5 MVA	N-1[234]	< 3 hours
	Urban & Non Urban (<10MVA)	Not Stated	Composite of N-1 & energy at risk	Not Stated	< 10 MVA	N[2]	Best practice repair time	< 10 MVA	N[2]	Best practice repair time	< 10 MVA	N[2]	Best practice repair time	Any	N-1[3, 8]		<5MVA	N[4]	Best practise repair but up to 12 hours.	<5 MVA	N	Best practise repair but up to 12 hours
Distribution Feeder	CBD	22 kV 10 MVA continuous and 15 MVA emergency for typically one hour ; 11 kV 5MVA continuous and 7.5 MVA emergency for typically one hour	N-1 in general	Not Stated	Any	N-1[3]	Nil	Any	N-1[3]	Nil	Any	NA		Any	N-1[4, 5, 6]		Any	N-1	Nil	Any	NA	
	Urban (town > 15,000)		Composite of N-1 & energy at risk	Not Stated	Any	N-1[4]	< 4 hours[5]	Any	N-1[4]	< 4 hours[5]	Any	N-1[3]	< 4 hours[4]	Any	N[2]		Any	N-1[5]	<2hrs	Any	N-1[5]	Best practise repair but up to 12 hours
	Urban (town < 15,000)		Composite of N-1 & energy at risk											Any	N		Any	N	Best practise repair but up to 12 hours.	Any	N-1[5]	Best practise repair but up to 12 hours
	Non-Urban	Not Stated	Composite of N-1 & energy at risk	Not Stated	Any	N	Best practice repair time	Any	N	Best practice repair time	Any	N	Best practice repair time	Any	N		Any	N[6]	Best practise repair but up to 12 hours.	Any	N	Best practise repair but up to 12 hours
Distribution Substation	CBD	Not Stated	N-1 in general	Not Stated	Any	N-1[3]	Nil	Any	N-1[3]	Nil	Any	NA					Any	N-1	Nil	Any	NA	
	Urban & Non Urban	Not Stated	Composite of N-1 & energy at risk	Not Stated	Any	N[7]	Best practice repair time	Any	N[7]	Best practice repair time	Any	N[5]	Best practice repair time				Any	N	Best practise repair but up to 12 hours.	Any	N	Best practise repair but up to 12 hours

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Summary of Standardised Supply Security Criteria - NOTES

	South Australia	Victoria					Tasmania	New South Wales & ACT				Queensland	
	ETSA	CitiPower	Powercor	Jemena	SP AusNet	United Energy	Aurora	Energy Australia	Integral Energy	Country Energy	Actew AGL	ENERGEX	Ergon Energy
1								For a *sub-transmission line - overhead* and a zone substation: under N-1 conditions, the *forecast demand* is not to exceed the *thermal capacity* for more than 1% if the time i.e. A total aggregate time of 88 hours per annum, up to a maximum of 20% above the *thermal capacity* under N-1 conditions. For Country Energy, in other than regional centres, the *forecast demand* must not exceed the *thermal capacity* under N-1 conditions. under N conditions, a further criterion is that the *thermal capacity* is required to meet at lease 115% of forecast demand. For a *sub-transmission - Underground,* any overhead section may be designed as if it was a *sub-transmission line - Overhead,* providing the *forecast demand* does not exceed the *thermal capacity* of the underground section at any time under N-1 conditions.	For a *sub-transmission line - overhead* and a zone substation: under N-1 conditions, the *forecast demand* is not to exceed the *thermal capacity* for more than 1% if the time i.e. A total aggregate time of 88 hours per annum, up to a maximum of 20% above the *thermal capacity* under N-1 conditions. For Country Energy, in other than regional centres, the *forecast demand* must not exceed the *thermal capacity* under N-1 conditions. under N conditions, a further criterion is that the *thermal capacity* is required to meet at lease 115% of forecast demand. For a *sub-transmission - Underground,* any overhead section may be designed as if it was a *sub-transmission line - Overhead,* providing the *forecast demand* does not exceed the *thermal capacity* of the underground section at any time under N-1 conditions.	For a *sub-transmission line - overhead* and a zone substation: under N-1 conditions, the *forecast demand* is not to exceed the *thermal capacity* for more than 1% if the time i.e. A total aggregate time of 88 hours per annum, up to a maximum of 20% above the *thermal capacity* under N-1 conditions. For Country Energy, in other than regional centres, the *forecast demand* must not exceed the *thermal capacity* under N-1 conditions. under N conditions, a further criterion is that the *thermal capacity* is required to meet at lease 115% of forecast demand. For a *sub-transmission - Underground,* any overhead section may be designed as if it was a *sub-transmission line - Overhead,* providing the *forecast demand* does not exceed the *thermal capacity* of the underground section at any time under N-1 conditions.	Load not to exceed continuous time rating for more than 1% of the time?		
2	Interconnected metropolitan 66 kV subtransmission	Estimates of energy at risk are made based on the 50 POE forecasts of zone substation maximum demand and assume a transformer outage lasting 2.5 months.	Estimates of energy at risk are made based on the 50 POE forecasts of zone substation maximum demand, and assume a transformer outage lasting 2.5 months.					Under N conditions, thermal capacity is to be provided for greater than 115% of forecast demand.		Under N conditions, thermal capacity is to be provided for greater than 115% of *forecast demand.*	Load not to exceed continuous rating by 20% or more.	Subtransmission feeders: Commercial, industrial, tourism (>5MVA) full N-1; very large industrial (>20MVA) N-1 (transfers for N-2); urban medium density – loss of supply but load can be restored by remote switching (15 mins). Some form of alternate supply for all loads except rural townships (<15MVA) and rural farming/production (<5MVA).	N-1(A); full N-1 under normal circumstances; possible momentary outage during automatic change-over of <60 seconds. Applies to Zone Subs >25 MVA
3	Radial metropolitan 66 kV subtransmission	In October 2007, the ESC handed down its Draft Determination approving the implementation of an n-1 secure system in the CBD of Melbourne. Work to implement N-1 secure is to be completed by 2012. The final decision by Citiower to implement N-1 Secure is contingent upon the conditions to be imposed by the ESC in their Final determination on this matter.	Full capacity (N) at zone substation level is expected to be available on average for 99.7% of the time, at which point an independent generator is considered as a reliable generation source, and as compensation for load.					The actual Security Standard is an enhanced N-1. For a second coincident credible contingency on the CBD triplex system, restricted essential load can still be supplied.		By 30 June 2014, expected demand is to be no more than 80% of feeder themal *capacity (under system normal operating conditions) with switchable interconnection* to adjacent feeders enabling restoration for an unplanned network element failure. By 30 June 2019, expected demand is to be no more than 75% of feeder themal capacity. In order to achieve compliance, feeder reinforcement pojects may need to be undertaken over more than one regulatory period. In those cases where a number of feeders form an interrelated system (such as a meshed network), the limits apply to the average loading of the feeders within the one system.	Load not to exceed 2 hour emergency rating of the substation.	Bulk Supply Substations: Urban/rural fringe loads might experience loss of supply but load can be restored by remote switching (15 mins). Some form of alternate supply for all loads except rural townships (<15MVA) and rural farming/production (<5MVA).	N-1(B); Expect short outage of up to 30 minutes while remote switching restores supply. Applies to Zone Substations with loads from 15 to 25 MVA
4	Other 66 kV Subtransmission and rural 33 kV	There are no “hurdle” load magnitudes above which N-1 or N-1 secure capacity is provided. All system augmentation is based on energy at risk, and other network/technical/economical considerations. Initial “trigger” is at about 150 hrs pa of risk.	Powercor operate 3 basic designs of zone substation, namely single transformer stations (n security, with supply restoration by manual switching on the distribution system), banked transformer stations (N-1 security, with supply restoration after isolation of the faulty transformer) and fully switched stations (N-1 security with no loss of supply for a failed transformer.					By 30 June 2014, expected demand is to be no more than 80% of feeder thermal *capacity (under system normal operating conditions) with switchable interconnection to* adjacent feeders enabling restoration for an unplanned network element failure. By 30 June 2019, expected demand is to be no more than 75% of feeder thermal capacity. In order to achieve compliance, feeder reinforcement projects may need to be undertaken over more than one regulatory period. In those cases where a number of feeders form an interrelated system (such as a meshed network), the limits apply to the average loading of the feeders within the one system.		The timeframe is expected only, and is based on the need to carry out the isolation and restoration switching referred to in note 4. This standard does not apply to interim/staged supplies, i.e. prior to completion of the entire development or to *excluded interruptions outside the control of the licence holder.*	Feeder load not to exceed feeder firm capacity for more than 2% of the time.	Zone substations; Urban > 5MVA - expect loss of supply but load can be restored by either remote (15 min) or manual (<2 hr) switching; Rural > 15MVA – expect loss of supply but load can be restored by field switching (< 2 hrs).). Some form of alternate supply for all loads except urban/rural fringe; rural townships (<15MVA) and rural farming/production (<5MVA).	N-1(C); Expect loss of supply but load can be restored by manual (<3 hr) switching. Applies to zone substations with loads from 5 to 15 MVA.
5	All City of Adelaide 66/33kV ans 66/11 kV substations	In urban and non-urban areas (i.e. excluding the CBD) the primary distribution system is generally designed to enable the load of 3 feeders to be carried on 2 feeders (i.e. the 66% principal) in the event of an N-1 contingency. The load would be transferred manually. Duration of outage not mandated.	In urban areas the primary distribution system is generally designed to enable the load of 3 feeders to be carried on 2 feeders (i.e. the 66% loading principle), whereas feeders classified as “rural short” are loaded up to 80% of rating, and feeders classified as “rural long” are loaded up to 100% of rating.					The timeframe is expected only, and is based on the need to carry out the isolation and restoration switching referred to in note 4. This standard does not apply to interim/staged supplies, i.e. prior to completion of the entire development or to *excluded interruptions outside the control of the licence holder.*		Urban Distribution substations shared, or available to be shared, by multiple customers are generally expected to have some level of redundancy for an unplanned contigency, eg via low voltage manual interconnection to adjacent substations enabling at least partial restoration.	Load not to exceed feeder firm capacity by more than 20%	Expect loss of supply but load can be restored by manual switching in <2hrs.	3 into 2 feeders at zone substation bus may require manual switching (<3 hrs); otherwise N.
6	Specific Major substations namely: Edinburg, Port Stanvac	For distribution substations in the CBD, N-1 transformer capacity is only provided for “critical loads” i.e. supply to major financial, commercial, hospitals or retail centres and buildings.						In the CBD area, N-2 equivalent is achieved by the network being normally configured on the basis of N-1 with no interruption of supply when any one line or item of electrical *apparatus within a substation is out of service. The licence holder must plan the CBD* network to cater for two credible contingencies involving the loss of multiple lines or items of electrical apparatus within a substation, by being able to restore supply within 1 hour. Restoration may be via alternative arrangements (e.g. 11kV interconnections).			Feeder firm capacity is calculated by reference to feeder thermal characteristics and network confirguration.	Rural production>5MVA may have capacity to restore supply by manual switching in <2 hrs.	

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Summary of Standardised Supply Security Criteria - NOTES

	South Australia	Victoria					Tasmania	New South Wales & ACT				Queensland	
	ETSA	CitiPower	Powercor	Jemena	SP AusNet	United Energy	Aurora	Energy Australia	Integral Energy	Country Energy	Actew AGL	ENERGEX	Ergon Energy
7	Other metropolitan 66/11kV substations							Urban Distribution substations shared, or available to be shared, by multiple customers are generally expected to have some level of redundancy for an unplanned contingency, eg via low voltage manual interconnection to adjacent substations enabling at least partial restoration.			Distribution transformer loading limit is 130% of continuous rating.		
8	66/7.6kV substations supplying major industrial customers or critical commercial loads, or where mobile cannot be used (Tonsley Park, North Adelaide, Kilkenny, Lefevre, New Osbourne, Kent Town, Norwood)										Zone substation transformer 2 hour emergency rating limited to 140% of continuous rating.		
9	Barossa/Mid North & Yorke Peninsula/ 80% within 3 hours Riverland/Murrayland 90% within 5 hours Eastern Hills/Fleurieu Peninsula 80% within 3 hours, 90% within 4 hours Upper North/Eyre Peninsula 80% within 4 hours, 90% within 6 hours South East 80% within 4 hours, 90% within 5 hours Kangaroo Island N/A												

Appendix B Summary of Reliability & Quality of Supply Obligations / Objectives

QH99920 – Appendix B - AEMC – National Framework for Electricity Distribution Network Planning and Expansion

Summary of Reliability and Quality of Supply Obligations / Objectives

		South Australia	Victoria					Tasmania	New South Wales & ACT				Queensland	
		ETSA Utilities	Citipower	Powercor	Jemena	SP AusNet	United Energy	Aurora	EnergyAustralia	Integral	Country Energy	ActewAGL	ENERGEX	Ergon Energy
Network Characteristics														
1.	Network length (route km)-HV,MV &LV.	86,000 km	6,445 km	82,000 km	12,600 km	2,300 km (66 kV) 33,000 km (≤22 kV)	12,600 km	<u>HV</u> 15,358 km OHL 840 km UG <u>LV</u> 7,350 km OHL 913 km UG	48,590 km	29,394 km	200,000 km (approx)	5,396 km	51,349 km	146,985 km
2.	% u/g / % o/h	17% UG, 83%OH	37%UG, 63%OH	5%UG, 95%OH	Not found	0.5%UG, 99.5% OH	Not found	8%UG, 92%OH	28%UG, 72%OH	31%UG, 69%OH	3%UG, 97%OH	54%UG, 46%OH	28.8%UG, 71.3%OH	3.5%UG, 96.5%OH
3.	Main primary distribution voltage	11 kV	22 kV & 11 kV	22 kV	22 kV	22 kV	22 kV	22 kV & 11 kV	11 kV	11 kV	22 kV	11 kV	11 kV	11 kV, 22 kV & SWER
Local Jurisdictional Obligations – supply reliability														
7.	Name of code or standard	ESCOSA Electricity Distribution Code	ESC Electricity Distribution Code	ESC Electricity Distribution Code	ESC Electricity Distribution Code	ESC Electricity Distribution Code	ESC Electricity Distribution Code	NER schedule 5.1 and Tasmania Reliability Performance Standard	Design, Reliability & Performance Licence Conditions.	Design, Reliability & Performance Licence Conditions	Design, Reliability & Performance License Conditions	ACT Distribution Code	QLD Electricity Industry Code	QLD Electricity Industry Code
8.	Reliability reporting in place?	Report to ESCOSA	Report to ESC	Report to ESC	Report to ESC	Report to ESC	Report to ESC	Report to OTTER	Report to IPART & Minister	Report to IPART & Minister	Report to IPART & Minister	Report to CEO of ActewAGL	Report to QCA Quarterly	Report to QCA Quarterly
9.	Bonus / penalty scheme in place?	Yes, ESCOSA Service incentive scheme in place	Yes. S-factor regime in place	Yes. S-factor regime in place	Yes. S-factor regime in place	Yes. S-factor regime in place	Yes. S-factor regime in place	No. Target only, to be achieved by 2012.	No	No	No	No	No	No
10.	Method for determining exclusions	EDC by ESCOSA	Per 6.3.4 of the Code.	Per 6.3.4 of the Code.	Per 6.3.4 of the Code.	Per 6.3.4 of the Code.	Per 6.3.4 of the Code.	All in, no exclusion	2.5Beta (SAIDI)	Not found	Not found	Customer impact method (>10%)	2.5 Beta (SAIDI) Refer Section 5.6.1	2.5 Beta (SAIDI) Refer Section 5.6.1
11.	Level of disaggregation (e.g. system / CBD / urban / short rural / long rural / individual feeder)	CBD / Urban / Rural?	CBD / Urban	Urban / Short rural / Long rural	Urban / Short rural	Urban / Short rural / Long rural	Urban / Short rural	CBD / Urban / Rural. 5 categories of criticality defined.	CBD / Urban / Short rural / Long rural	Urban / Short rural / Long rural	Urban / Short rural / Long rural	System	CBD / Urban / short rural / long rural / isolated feeder	CBD / Urban / short rural / long rural / isolated feeder
12.	Other criteria reported (e.g. excluded interruption / customer service standards / major event days)	Not Stated	Nil.	Nil.	Nil.	Nil.	Nil.	Schedule 8.1 of TEC – formula for reliability calculation	Indiv. Feeder Stds Excluded interruptions. Customer Service Stds. Major event days.	Indiv. Feeder Stds Excluded interruptions. Customer Service Stds. Major event days.	Indiv. Feeder Stds Excluded Interruptions Customer Service Stds. Major event days.	QoS	▪ GSL's ▪ Summer Preparednes s ▪ Network Management Plans ▪ QOS	▪ GSL's ▪ Summer Preparednes s ▪ Network Manage-ment Plans ▪ QOS
13.	System SAIDI target (2009/10)	CBD – 25 min Major Metro-115min Others-240 to 330min	(06-10 target) CBD – 19.9min Urban– 44.9min	(06-10 target) Urban-114min S rural – 153min L rural – 367min	(2007 target) 84min (overall)	(2007 target) Urban-107min S rural – 184min L rural – 309min	65 min	(07/08 average target) CBD-30min Urban-120min Rural-480min	CBD – 48min Urban-82 min Sh rural-320min L.rural-740min	Urban – 82min Sh rural-300min L.rural – n/a	Urban – 128min Sh.rural 308min L.rural – 710min	91.0 min (or better)	CBD: 20 min Urban: 110 min Short Rural: 220 min	Urban:2.00 Short Rural: 4.00 Long Rural: 7.50
14.	System SAIFI target (2009/10)	CBD-0.3 Major Metro-1.4 Others- 2.1 to 2.7	0.7 for entire network (CBD+Urban)	(06-10 target) Urban-1.72 S rural – 1.95 L rural – 3.55	(2007 target) 1.22 (overall)	(2007 target) Urban-1.5 S rural – 2.2 L rural – 3.4	1.22 for entire network	CBD-1 Urban-2 Rural-6	CBD- 0.31 Urban- 1.22 Sh. Rural-3.4 L. Rural- 6.5	Urban – 1.22 Sh.rural-2.8 L.rural – n/a	Urban – 1.84 Sh.rural-3.06 L.rural-4.6	1.2 (or better)	CBD: 0.33 Urban: 1.32 Short Rural: 2.50	Urban:2.00 Short Rural:4.00 Long Rural: 7.50
15.	Period targets are set for? (e.g. 2009 – 2014)	2010-2014	2011-2015	2011-2015	2011-2015	2011-2015	2010	2008-2012	To 2010/11	To 2010/11	To 2010/11	Target fixed for an unstated period.	2010/11 – 2014/15 (Indicative only)	2008/09 – 2012/13 (Indicative Only)
16.	Are SAIDI & SAIFI targets for planned & unplanned, or unplanned only?	Planned & Unplanned	Planned & Unplanned	Planned & Unplanned	Planned & Unplanned	Planned & Unplanned	Planned & Unplanned	Planned & Unplanned	Unplanned only.	Unplanned only.	Unplanned only.	Planned & unplanned	Planned & Unplanned (excl customer installations faults)	Planned & Unplanned (excl customer installations faults)

QH99920 – Appendix B - AEMC – National Framework for Electricity Distribution Network Planning and Expansion

Summary of Reliability and Quality of Supply Obligations / Objectives

		South Australia	Victoria					Tasmania	New South Wales & ACT				Queensland	
		ETSA Utilities	Citipower	Powercor	Jemena	SP AusNet	United Energy	Aurora	EnergyAustralia	Integral	Country Energy	ActewAGL	ENERGEX	Ergon Energy
Local Jurisdictional Obligations – supply quality														
19.	Name of code or standard	EDC by ESCOSAand NER	ESC Electricity Distribution Code	ESC Electricity Distribution Code	ESC Electricity Distribution Code	ESC Electricity Distribution Code	ESC Electricity Distribution Code	TEC	NER Chapter & Schedule 5 plus ??	NER Chapter & Schedule 5 plus ??	NER Chapter & Schedule 5 plus ??	ACT Distribution Code	NER Chapter & Schedule 5	NER Chapter & Schedule 5
20.	QoS measuring in place?	Yes	Yes	Yes	Yes	Yes	Yes		??	??	??	??	No	Yes
21.	Extent / location of QoS monitoring?	Not stated	Zone sub and end of longest feeder	Zone sub and end of longest feeder	Zone sub and end of longest feeder	Zone sub and end of longest feeder	Zone sub and end of longest feeder		??	??	??	??	Limited, in response to complaints	Existing – 4— PQ meters Planned (08/09) – 1600 PQ meters
22.	Is QoS monitoring reactive or proactive?	Not stated	Proactive & Reactive in response to customer complaints	Proactive & Reactive in response to customer complaints	Proactive & Reactive in response to customer complaints	Proactive & Reactive in response to customer complaints	Proactive & Reactive in response to customer complaints		??	??	??	??	Historically reactive proposal proactive from 2009/10	Proactive
23.	QoS parameters monitored? (e.g. MAIFI, voltage, harmonics, flicker, etc.)	Voltage/harmonic/ voltage unbalance	Freq/voltage/ power factor/ Harmonics/ inductive interference/ Neg seq voltage/ load balance/	Freq/voltage/ power factor/ Harmonics/ inductive interference/ Neg seq voltage/ load balance/	Freq/voltage/ power factor/ Harmonics/ inductive interference/ Neg seq voltage/ load balance/	Freq/voltage/ power factor/ Harmonics/ inductive interference/ Neg seq voltage/ load balance/	Freq/voltage/ power factor/ Harmonics/ inductive interference/ Neg seq voltage/ load balance/		??	??	??	▪ Voltage dips / transients. ▪ Neutral / earth diff. ▪ Earth rise. ▪ Volt. Unbalance. ▪ DC. ▪ EMF. ▪ Harmonics.	▪ Steady stage Voltage ▪ Voltage sags & swells ▪ Harmonic Distortion ▪ Voltage unbalance (all proposed)	▪ Steady stage Voltage ▪ Voltage sags ▪ Harmonic Distortion ▪ Voltage unbalance (Trends monitored over 2002/3 to 2006/07)
24.	Is QoS regulatory reporting in place?	No	YES	YES	YES	YES	YES		??	??	??	Report to CEO of ActewAGL	No	Member of National Power Quality Survey (LTNPQS)
25.	Does a bonus / penalty scheme apply?	No	No	No	No	No	No		No	No	No	No	No	No
26.	Are any targets in place?	No	No	No	No	No	No		??	??	??	Generally to Aust. Standards	Generally to Aust Standards	Generally to Aust Standards

Appendix C Summary of Load Forecasting Methodologies

QH99920 – Appendix C - AEMC – National Framework for Electricity Distribution Network Planning and Expansion

Summary of Maximum Demand Forecasting Methodologies

		South Australia		Victoria										Tasmania		New South Wales & ACT								Queensland			
		ETSA Utilities		Citipower		Powercor		Jemena		SP AusNet		United Energy		Aurora		EnergyAustralia		Integral		Country Energy		ActewAGL		ENERGEX		Ergon Energy	
		Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment
System Level																											
1.	Is system wide MD forecast externally prepared or reviewed?		Not stated	Y	NIEIR, Victorian wide	Y	NIEIR, Victorian wide	Y	NIEIR, Victorian wide	Y	NIEIR, Victorian wide	Y	NIEIR, Victorian wide		Not stated	?	Not stated.	Y	Reviewed by CRA Int.(Confidential)	Y	Prepared by NIEIR	Y	Prepared by SKM	Y	Reviewed by ACIL Tasman	?	Not stated
2.	What are the underpinning methodologies used in the system wide MD forecast? (Trend Analysis/Population Forecasts/ End Use Energy Analysis/Customer Category Forecasts/Macroeconomic Indicators/etc)		Not stated	Y	Econometiric model based on industry O/P, Electricity prices and ambient temperature.	Y	Econometiric model based on industry O/P, Electricity prices and ambient temperature.	Y	Econometiric model based on industry O/P, Electricity prices and ambient temperature.	Y	Econometiric model based on industry O/P, Electricity prices and ambient temperature.	Y	Econometric model based on industry O/P, Electricity prices and ambient temperature.		Not stated	Y	Trend / Committed projects / Econometric / Customer category/ Pop'n.	?	Trend / Weather / Demographics / Socio-economic Factors.	Y	Trend / Econometric Variables(Pop'n, Economic activity, Price, Fuel substitution)/Customer Category	Y	Trend / Econometric Variables (Pop'n, Economic Activity, Price, Fuel substitution)/ Customer Category	Y	Econometric/ Trend/ Customer Category/ Pop'n Census/ Monte Carlo/ Regression.	?	Not stated
3.	What is the period of the system wide MD Forecast? (5yr/10yr?)		Not stated		Not Stated		Not Stated		Not Stated		Not Stated		Not Stated		10 Yrs	Y	5yrs	?	5yrs	Y	5 yrs	Y	10yrs	Y	10yr	Y	10 years
4.	Is the system wide MD forecast supported by energy consumption & customer growth forecasts?	Y	Included the govt initiated or supported (i.e. SA water & Defence)		Not Stated		Not Stated		Not Stated		Not Stated		Not Stated		Not Stated	Y	Energy Forecast, Yes. Customer Forecast, not stated.	Y	Details in confidential report.	Y		Y	Energy forecast, Yes. Customer forecast, No.	Y	Also reviewed by ACIL Tasman	Y	
5.	Are 10%, 50% & 90% PoE MD forecasts produced or high/medium/low forecasts?	Y	High/Moderate/Low	Y	10%, 50% & 90%	Y	10%, 50% & 90%	Y	10%, 50% & 90%	Y	10%, 50% & 90%	Y	10%, 50% & 90%	Y	10%, 50% & 90%	?	Not stated	Y	Details in confidential report.	Y	10%,50%, 90%PoE	Y	10%, 50%, 90% PoE	Y	10%/50%/ 90% PoE.	Y ?	10% & 50%PoE forecasts produced.
6.	Are historical system MD's weather corrected or are abnormal MD's adjusted in another way?	Y	Weather corrected based on extreme hot days		Not Stated		Not Stated		Not Stated		Not Stated	Y	Not Stated		Not Stated	Y	Corrected to "normal" weather.	?	Not stated	Y	Weather corrected	Y	Weather corrected.	Y	Weather corrected based on temperature data at Amberley	N	Not weather corrected due to geographic diversity.
7.																											
8.																											
Bulk Supply and Zone Substation Demand Forecasts																											
9.	Are Bulk Supply & Zone Substation Forecasts externally prepared or reviewed?		Not stated		Not Stated		Not Stated		Not Stated		Not Stated		Not Stated		Not Stated	?	Not stated	?	Not stated.	Y	Prepared internally	Y	Prepared by SKM	Y	Reviewed by ACIL Tasman	?	Not stated
10.	What are the underpinning methodologies used in Bulk Supply & Zone Subs Forecasts? (Trend Analysis, etc)		Extreme hot days/Known demands/ Economic factors/ DM		Historic max load/ Step load changes/ Load transfer/		Historic max load/ Step load changes/ Load transfer/		Economic activities/ growth patterns/ risk/ Regulatory/ customer expectation		Historic max load/ Step load changes/ Load transfer/		Historic max load/ Step load changes/ Load transfer/		Seasonal load/ customer surveys/ govt programs/ DM	Y	Trend/ committed projects/ load transfers / Econometric / Pop'n	?	Not stated.	Y	Trend / load transfers / spot load adjustment	Y	Reconciled to System MD/ Trend / Dynamic Econometric/ Spot load removal.	Y	Trend / Pop'n Census / Other?	Y	Long term, 10 year trend of historical actual loads.

QH99920 – Appendix C - AEMC – National Framework for Electricity Distribution Network Planning and Expansion

Summary of Maximum Demand Forecasting Methodologies

		South Australia		Victoria										Tasmania		New South Wales & ACT								Queensland			
		ETSA Utilities		Citipower		Powercor		Jemena		SP AusNet		United Energy		Aurora		EnergyAustralia		Integral		Country Energy		ActewAGL		ENERGEX		Ergon Energy	
		Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment
11.	What is the period of the Bulk Supply/Zone sub forecast? (5yr/10yr?)		Annually produce -3 year Feeder Exit Load Forecast -10 Year Substation Load Forecast -5 year Subtransmission Line Load Forecast		Z/S 5 Yrs BSP 10Yrs		Z/S 5 Yrs BSP 10Yrs		Z/S 5 Yrs BSP 10Yrs		Z/S 5 Yrs BSP 10Yrs		Z/S 5 Yrs BSP 10Yrs	Y	10 Yrs	Y	Zone S/S – 7yrs. STS – 10 yrs.	Y	5 yrs	Y	ESDR – 5yrs	Y	10 yrs.	Y	10yr	Y	5 yrs
12.	Is the Bulk Supply forecasts reconciled to the system wide forecast and zone sub to bulk supply?		Not stated		Not stated		Not stated		Not stated		Not stated		Not stated		Not stated	?	Not stated	?	Not stated.	Y	Reconciled with NIEIR forecast	Y	Zone sub. To system MD reconciled.	Y ?		Y	Coincidence factors applied.
13.	Are 10%, 50% & 90% PoE MD Forecasts produced at BSP/Zone S/S level or high/medium/low forecasts?		High/Moderate/Low		50% PoE (long term) Also consider 10%PoE (short term)		50% PoE (long term) Also consider 10%PoE (short term)		50% PoE (long term) Also consider 10%PoE (short term)		50% PoE (long term) Also consider 10%PoE (short term)		50% PoE (long term) Also consider 10%PoE (short term)		50% PoE	?	Not stated	Y	50%PoE forecasts at STS and Z/S level	Y	50%PoE at Zone Sub Level	Y	10%, 50%, 90% PoE	Y	50%PoE	Y	10% & 50% PoE forecasts produced.
14.	Are temporary load transfers between substations recorded and removed from historical and forecasts loads? (e.g. planned or emergency switching)	Y	Check annually	Y	Both emergency and long term	Y	Both emergency and long term	Y	Both emergency and long term	Y	Both emergency and long term	Y	Both emergency and long term	Y	Both emergency and long term	Y	Load transfers accounted for.	?	Not stated.	Y	Load transfers accounted for.	?	Not stated.	Y	Load transfers accounted for	Y	Load transfers accounted for.
15.	Are historical spot load increases removed before trend projections performed?		Not stated		Not stated		Not stated		Not stated		Not stated		Not stated		Not stated	?	Not stated	?	Not stated.	Y	Spot loads adjusted.	Y	Removal of spot loads confirmed.	?	Not stated.	?	Not stated.
16.	Are historical BSP and Zone Sub historical loads weather corrected or are abnormal MD's adjusted in another way? How?		Not stated		Weather Corrected		Weather Corrected	Y	Use 50% PoE to cover abnormal MD.	Y	Weather corrected to produce 50% & 10% PoE forecast.		one in ten year weather probability event		Not stated	?	Not stated	?	Not stated	Y	Use 50%PoE to cover abnormal MD	Y	Weather corrected	Y	Load projections weather correcteda t system level, BSP level & Z/S level.	N	Not weather corrected due to geographi c diversity.
17.																											
18.																											
Distribution Feeder Demand Forecasts																											
19.	Is a forecast of distribution feeder MD's produced? If so, how long? (3Yr/5Yr?)		1 yr, publish annually	Y	5 Yrs	Y	5 Yrs	Y	5 Yrs	Y	5 Yrs	Y	5 Yrs		10 Yrs	?	Not stated	?	Not stated	N	Will do so for spot load and customer requirements.	?	Not stated.	?	Not stated	?	Not stated
20.	Are load flows and steady state voltage profiles modelled, based on forecasts? If so, how often?		Not stated	Y	Mathematical model build based on 5 yrs forecasts	Y	Mathematical model build based on 5 yrs forecasts	Y	Mathematical model build based on 5 yrs forecasts	Y	Mathematical model build based on 5 yrs forecasts	Y	Mathematical model build based on 5 yrs forecasts	Y	Use DINIS model	?	Not stated	?	Not stated	N	CE plans to establish modelling	?	Not stated.	?	Not stated.	?	Not stated
21.	Are temporary load transfers between zone substations recorded and removed from historical & forecast loads? (e.g. planned or emergency switching)	Y	Check annually	Y	Check annually	Y	Check annually	Y	Not stated	Y	Check annually	Y	Check annually		Not Stated	Y	Load transfers accounted for.	?	Not stated	N	If forecast is produced, load transfers are accounted for.	?	Not stated.	?	Not stated.	?	Not stated

Appendix D Summary of Economic Analysis Methodologies

QH99920 – Appendix D - AEMC – National Framework for Electricity Distribution Network Planning and Expansion

Summary of Economic Analysis Techniques Employed

		South Australia		Victoria										Tasmania		New South Wales & ACT								Queensland			
		ETSA Utilities		Citipower		Powercor		Jemena		SP AusNet		United Energy		Aurora		EnergyAustralia		Integral		Country Energy		ActewAGL		ENERGEX		Ergon Energy	
		Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment
Programme / project requiring regulatory test (M$10)																											
1.	Method of economic Analysis used (e.g. cost / benefit Analysis per regulatory test																										
2.	If project is a mix of replacement & augmentation is regulatory test conducted if augmentation >M$10																										
3.																											
4.																											
5.																											
Transmission / submission works not requiring regulatory test (≤M$10)																											
6.	Method of economic analysis used (e.g. NPV / ROR / min cost / etc)																										
7.	List of costs included in cost / benefit analysis: ■ Capital costs (direct) ■ Differences in O&M costs (direct) ■ Difference in annualized costs of losses ■ Differences in community cost of energy not supplied ■ Other (explain)																										
8.																											
9.																											
10.																											
Distribution augmentation works (typically >M$1.0/project / program)																											
11.	Method of economic analysis used (e.g NPV / ROR / min cost / etc)																										
12.	List of costs included in Cost/benefit analysis: ■ Capital costs of options (direct) ■ Differences in O&M costs (direct) ■ Difference in lifestyle costs between 0/4 and U/G ■ Differences in community cost of energy not supplied ■ Differences in annualize cost of losses ■ Other (explain)																										
13.																											
14.																											

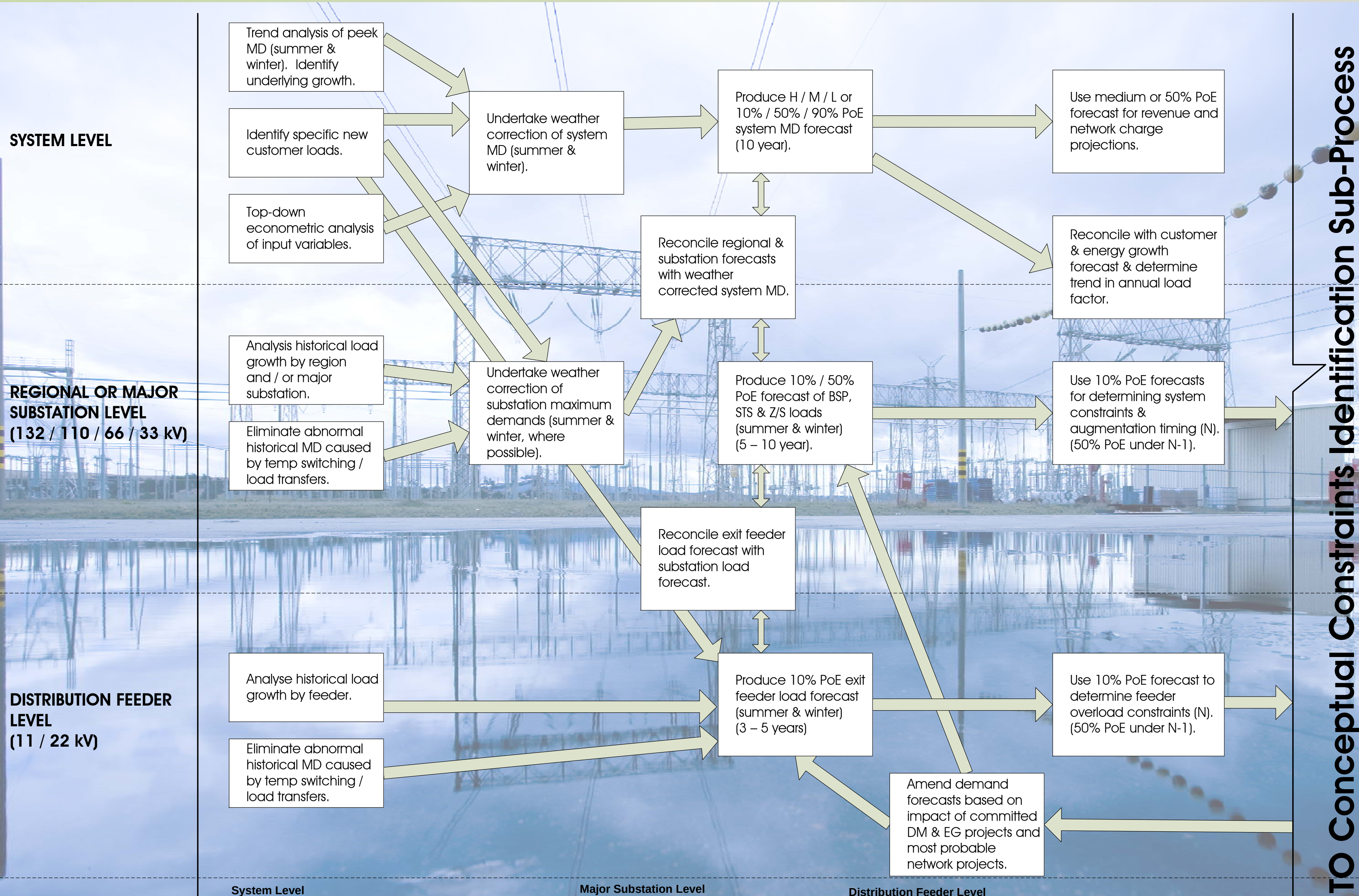
QH99920 – Appendix D - AEMC – National Framework for Electricity Distribution Network Planning and Expansion

Summary of Economic Analysis Techniques Employed

		South Australia		Victoria										Tasmania		New South Wales & ACT								Queensland			
		ETSA Utilities		Citipower		Powercor		Jemena		SP AusNet		United Energy		Aurora		EnergyAustralia		Integral		Country Energy		ActewAGL		ENERGEX		Ergon Energy	
		Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment	Y / N	Comment
15.																											
Distribution reliability works																											
16.	Method of economic analysis used (e.g. NPV / ROR / min cost / etc																										
17.	List of costs included in cost / benefit analysis: ▪ Capital costs of options (direct) ▪ Differences in O&M costs (direct) ▪ Difference in lifestyle costs between 0/4 and U/G ▪ Differences in community cost of energy not supplied ▪ Differences in annualize cost of losses ▪ Other (explain)																										
18.																											
19.																											
20.																											

Appendix E Conceptual Load Forecasting Sub-process

APPENDIX E – Conceptual Load Forecasting Sub-Process



BEST PRACTICE CHARACTERISTICS

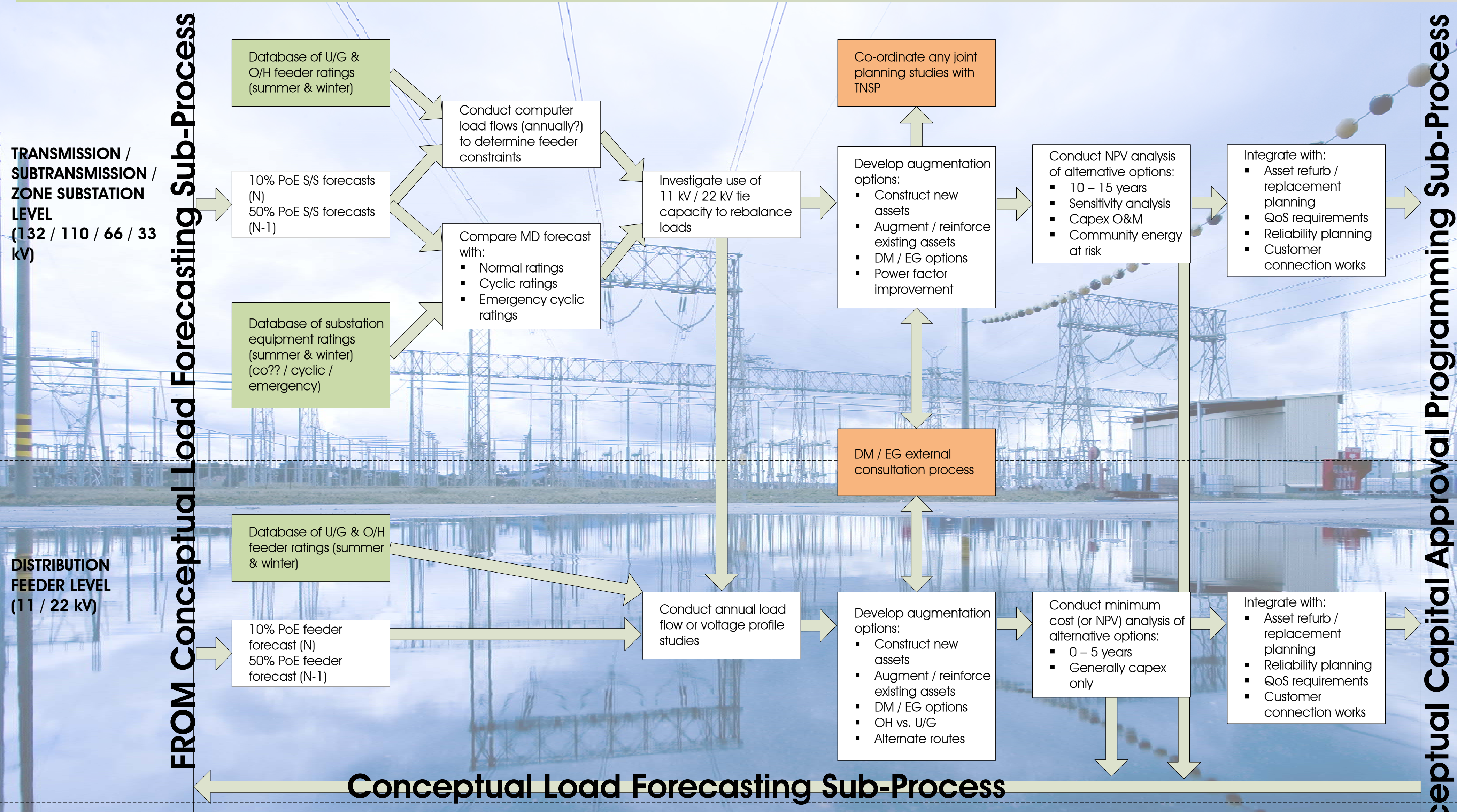
System Level
- Top down & bottom up forecasts
- Combine historical trend forecast with econometric modelling
- Eliminate spot loads from underlying trends
- Separate summer & winter forecasts
- External consultants to produce / review forecasts
- Produce 10% / 50% / 90% PoE system demand forecast
- Weather correct demand forecast
- Reconcile system MD forecast with BSP forecast
- Reconcile demand forecast with energy & customer forecast

Major Substation Level
- Trend analysis forecast
- Eliminate abnormal loads & load transfers
- Separate spot loads from underlying trends
- Weather correct substation loads
- Reconcile substation MD's with system MD
- Produce 10% & 50% PoE forecast

Distribution Feeder Level
- Trend Analysis Forecast, Eliminate abnormal loads and load transfers
- Separate spot loads from underlying trends, Reconcile feeder loads with substation MD
- Produce annual 3-5yr forecast
- Conduct annual assessment of load vs thermal rating and voltage drop.

Appendix F Conceptual Constraints Identification Sub-process

APPENDIX F – Conceptual Constraints Identification Sub-Process

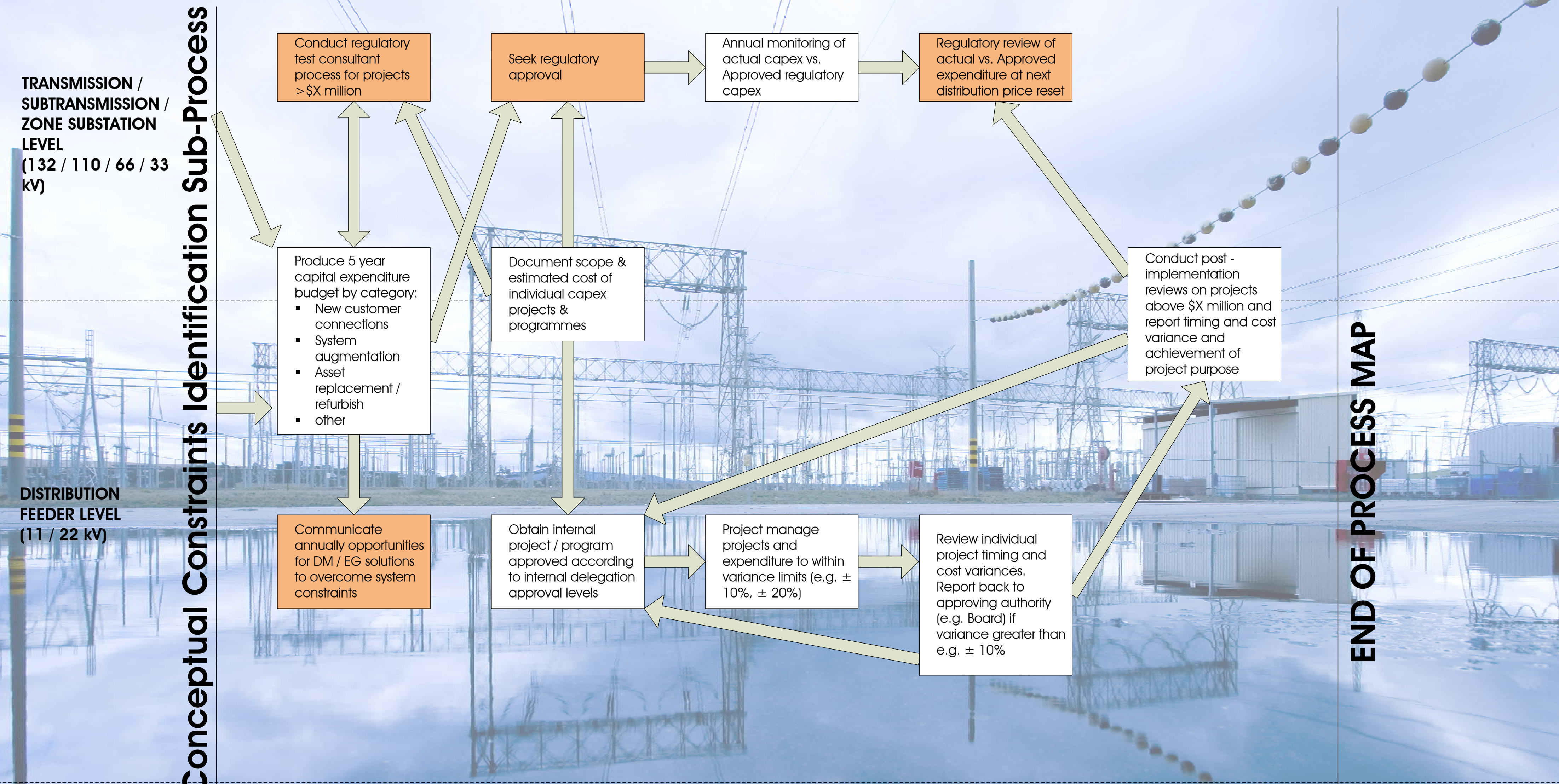


BEST PRACTICE CHARACTERISTICS

- Database of equipment ratings (Coded Green), Apply 10% PoE to N situations
- Apply 50% PoE to N-1 situations, Apply appropriate overload ratings (eg transformers), Apply dynamic loading ratings to feeders
- Maximise loads transfers to defer projects, Conduct annual trans. and sub-trans. load flows
- Conduct annual distribution load vs ratings and volt. Drop.
- NPV analysis for Trans. & Sub-trans. Projects, NPV or Minimum Cost Analysis for distribution projects, Documented & transparent process for DM/EG consultation(Coded Orange)
- Documented & transparent process for co-ordination with TNSP (Coded Orange)
- Integrate augmentation projects with scope and timing of other projects(eg reliability/refurbishment, etc)

Appendix G Conceptual Capital Approval Programming & Governance Sub-process

APPENDIX G – Conceptual Capital Approval Programming & Governance Sub-Process



BEST PRACTICE CHARACTERISTICS

- Documented and transparent process seeking external non-network solutions(Coded Orange)
- Documented and transparent process for Reg. Test(Coded Orange), Documented Capital Governance process in place
- Formal financial approvals and delegation, Capital Approvals Committee, Various stages of project scoping and estimated costs
- Project delivery performance criteria in place, Project post-implementation reviews in place.

SKM

Appendix H Relevant DNSP Planning Documents (published and / or regulatory submissions)

H.1 ETSA Utilities

Name / title of document	Publicly available? Y / N	Available for regulatory scrutiny?
1. ETSA Electricity System Development Plan	Y	Y
2. ETSA Utilities-ElectraNet Connection Agreement	Not stated	Y
3. ETSA Utilities' 5-year Capital Plan	Not stated	Y
4. Annual Demand Management Compliance Report	Y	Y
5. Network Planning Procedure	Not stated	Y

H.2 CitiPower / Powercor

Name / title of document	Publicly available? Y / N	Available for regulatory scrutiny?
1. CitiPower Distribution Planning Report	Y	Y
2. Powercor Distribution Planning Report	Y	Y
3. Joint DNSP TCPR	Y	Y
4. Annual Comparative Performance Report (ESCV)	Y	Y
5. Victorian Distribution Code	Y	Y

H.3 Jemena

Name / title of document	Publicly available? Y / N	Available for regulatory scrutiny?
1. Five-year Network Strategic Plan	Y	Y

H.4 SP AusNet

Name / title of document	Publicly available? Y / N	Available for regulatory scrutiny?
1. DSPR	Y	Y
2. 5 Years Asset Management Plan	N	Y
3. TCPR	Y	Y
4. Electricity Reliability Report	N	Y
5. Distribution loss factors (DLFs) reports	Y	Y

H.5 United Energy

Name / title of document	Publicly available? Y / N	Available for regulatory scrutiny?
1. Electricity Distribution Asset maintenance and Replacement Plan	N	Y
2. DSPR	Y	Y
3. TCPR	Y	Y
4. Electricity Reliability Report	N	Y
5. Distribution loss factors (DLFs) reports	Y	Y

H.6 Aurora Energy

Name / title of document	Publicly available? Y / N	Available for regulatory scrutiny?
1. Asset Management Plan	N	Y
2. DSPR	Y	Y

H.7 EnergyAustralia

Name / title of document	Publicly available? Y / N	Available for regulatory scrutiny?
1. Design, Reliability and Performance Licence Conditions for DNSP Minister for Energy Dec 2007	Y	Y
2. Joint TransGrid / EnergyAustralia Reliability Planning Criteria	N	Y
3. Area Plan Development Process	N	Y
4. Network Investment Governance Overview	N	Y
5. Energy and Global Peak Demand Forecasts to 2014	Y	Y
6. Spatial Forecasts Process	N	Y
7. Annual ESDR (AESDH) 2006/07, 2007/08	Y	Y
8. Planning Criteria	N	Y
9. NMP	Y	Y
10. Reliability Investment Plan	N	Y
11. Replacement Plan 2009-14	N	Y
12. Sub transmission Reliability Strategy	N	Y
13. Area Plans	N	Y
14. Duty of Care	N	Y

H.8 Integral Energy

Name / title of document		Publicly available? Y / N	Available for regulatory scrutiny?
1.	ESDR	Y	Y
2.	NER Consultation Reports	Y	Y
3.	NMP	Y	Y
4.	Electricity Network Performance Report	Y	Y
5.	Table of Forecasts of New Connections	N	Y
6.	Transmission Network Planning Report	N	Y
7.	Distribution Network Status Report	N	Y
8.	Demand Management Plan	N	Y
9.	Reliability Works Program	N	Y
10.	Strategic Asset Renewal Plan	N	Y
11.	Strategic Network Maintenance Plan	N	Y
12.	Network Asset Management Policy (9.0)	N	Y
13.	Network Planning Policy (9.2.1)	N	Y
14.	Power Quality Policy (9.1.4)	N	Y

H.9 Country Energy

Name / title of document		Publicly available? Y / N	Available for regulatory scrutiny?
1.	Design, Reliability and Performance Licence Conditions for DNSP Minister for Energy Dec 2007	Y	Y
2.	Electricity Supply Standard CEPG8026	Y	Y
3.	Sub-transmission & Distribution Network Planning Criteria and Guidelines	Y	Y
4.	Strategic Sub-transmission Planning Reports	Y	Y
5.	Spatial Load Forecasting Methodology	N/A	N/A
6.	NIEIR Demand and Energy Forecasts	N	Y
7.	Energy and Peak Demand Forecasts	Y	Y
8.	Annual ESDR 2006/07, 2007/08	Y	Y
9.	Network Asset Management Plan	N	Y
10.	Area Plans	N	Y
11.	Regional Centre Plans	N	Y
12.	Contingency Planning Reports	N	Y

SKM

H.10 ActewAGL

Name / title of document	Publicly available? Y / N	Available for regulatory scrutiny?
1. Network 10 year Augmentation Plan	N	Y
2. 10 year Customer Initiated Capital Investment Plan	N	Y
3. Technology & Information Management Strategy	N	Y
4. Metering Asset Management Plan	N	Y
5. Network Security Criteria	N	Y
6. Demand Management & Non-network Solutions Procedure	N	Y
7. Energy & Demand Forecasts	Y	Y
8. Annual Report on Quality & Reliability of Supply	N	Y
9. ActewAGL Distribution Asset Management Plan	N	Y

H.11 ENERGEX

Name / title of document	Publicly available? Y / N	Available for regulatory scrutiny?
1. NMP	Y	Y
2. Planning and Supply Manual	N	Y
3. Network Strategic Development Plan	N	Y
4. Network Development Plan	N	Y
5. Detailed Plans for individual projects	Y (>$1.0m)	Y
6. Contingency Plans	N	Y
7. Demand, Energy and Customer number forecasts	Y	Y
8. ACIL Tasman Review of ENERGEX demand forecast methodology	Y	Y

H.12 Ergon Energy

Name / title of document	Publicly available? Y / N	Available for regulatory scrutiny?
1. NMP	Y	Y
2. Network Planning Criteria NP02	N	Y
3. Network Security Criteria NPD05	N	Y
4. Regional Strategic Plans	N	Y
5. NIEIR Peak Demand and Energy Forecasts	N	Y
6. SNAPs	N	Y
7. DNAPs	N	Y