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# CAPACITY MANAGEMENT PLAN 2011

## (SYSTEM DEVELOPMENT THREAD)

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| REV NO. | DATE | REVISION DESCRIPTION | APPROVALS | |
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# 1. PURPOSE

The purpose of this document is to outline the methodology and the management of the risks associated with capacity constrained assets for either current loading or forecast future loading.

The period of this plan covers the years 2012/2013 to 2016/2017 in detail and has a ten-year window to 2021.

# 2. SCOPE

This plan covers the Network Initiated Capital Works (NICW) of the System Development Thread, which for system infrastructure associated with 44 kV, 33 kV, 22 kV, 12.7 kV, 11 kV and 400 V distribution systems.

Work within this plan has linkages to the following thread management processes:

1. Connection Assets;
2. Customer Generated Work;
3. Ground Mounted Substations;
4. HV Regulators;
5. Power Quality;
6. Overhead System;
7. Protection and Control;
8. Reliability;
9. System Operations;
10. Underground System; and
11. Zone Substations.

The exclusions to this management plan are Customer Initiated Capital Works (CICW) and Demand Management.

Whilst these two activities have major implications on the development of the system both have their own management plans. These inter-related activities enable new customer connections to be supported and for the effective implementation of non-network solutions, which offsets the need for augmentation.

# 3. REGULATORY AND LEGISLATIVE OBLIGATIONS

The regulatory and legislative obligations, relating to capacity related works include:

1. Electricity Supply Industry Act 1995 (ESI);
2. Tasmanian Electricity Code 2010 (TEC);
3. National Electricity Rules (NER);
4. National Electricity Law; and
5. Australian Standards.

# 4. ALIGNMENT TO STRATEGIC OBJECTIVES

This plan is aligned to the strategic objectives of the Network Management Strategy, particularly with respect to network investment.

The objective of the System Development thread is to develop the network in a prudent manner to deliver an effective and efficient, least cost, robust and reliable network, which does not result in cost increases to our customers.

# 5. CAPACITY RELATED ISSUES

The drivers for conducting network augmentation are:

1. Switchgear, transformers, cables and conductors not rated for load current;
2. Switchgear, transformers, cables and conductors not rated for fault current;
3. Suboptimal sizing of cables and conductors causing increased voltage drop and losses;
4. Circuit(s) not rated for load distribution i.e. transitioning from single phase to two or three phase distribution;
5. Switchgear not appropriate for task e.g. upgrading from single phase operation to three phase operation;
6. Circuits not capable of load transfer i.e. improving operational flexibility and management;
7. Changing the nominal system voltage e.g. migrating from 11 kV to 22 kV; and
8. Quality of supply issues including voltage flicker and waveform distortion associated with electrical loading of infrastructure.

# 6. LEVELS OF SYSTEM MANAGEMENT

Management of capacity outcomes is achieved through three levels of system planning:

1. Major System;
2. High Voltage System; and
3. Low Voltage System.

Within each of these levels there are a number of assessment considerations that enable prioritisation for treatment. These are shown in Figure 1.

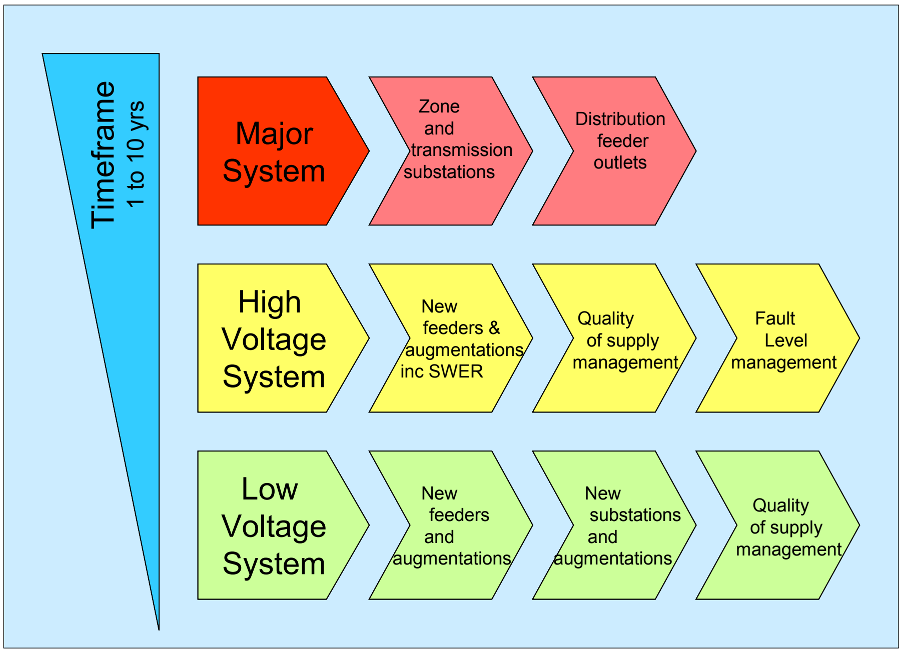


**Figure 1: Main processes**

## 6.1 Major System

This covers zone substations and subtransmission circuits operating at 33 kV.

As of June 2009 there were 10 major and six minor zone substations with 23 associated subtransmission circuits.

Work within this level also incorporates joint planning outcomes with Transend Networks Pty Ltd (Transend) as the Transmission Network Service Provider.

## 6.2 High Voltage System

This covers High Voltage (HV) feeders, switches, reclosers and interconnections operating at either 11, 12.7, 22 or 44 kV.

As at June 2010 there were:

- 386 HV feeders, with a total route length of 16,087 km;
- 329 Pole Mounted Reclosers (PMR); and
- 73 HV regulators.

## 6.3 Low Voltage System

This covers Low Voltage (LV) feeders, switches, distribution substations and interconnections operating at 400V.

As at June 2010 there were:

- 30,262 distribution substations comprising ground mounted and predominately pole mounted units; and
- 6,179 km of low voltage reticulation comprising underground and predominately overhead circuits.

# 7. DEMAND FORECAST

The demand forecasts (DF) are an essential tool in planning augmentations and development of the network. This enables effective and efficient management of loading limitations and understanding the level of risk that they present for the major system, the HV system and the LV system.

A 10 year DF is compiled by Aurora in its capacity as Distribution Network Service provider (DNSP) to meet distribution network demand planning needs, Transend planning needs, and support the Office of the Tasmanian Economic Regulator's (OTTER) annual reporting requirements in accordance with NER schedule 5.7.

## 7.1 Methodology

The underlying approach is to project load growth at each connection site with the transmission system and each zone substation at a rate that is consistent with recent history. These spatial forecasts, in maximum demand MWs, are based on the nature of customers in the region and their demand profiles taking into account subdivision and commercial development opportunities and economic indicators and relationships with energy demands.

The spatial forecasts at connection sites are aggregated together, using diversity factors, to a system level forecast (bottom-up).

This bottom-up forecast is compared with and reconciled to a Tasmanian system level forecast that is prepared separately by Transend, a top-down approach.

There is a review of the data to ensure that it is consistent with the expectations of the planning staff.

Daily load profiles by season, working day and non-working days are based on historic profiles.

To produce the connection site forecasts used for system augmentation planning, where appropriate the base-line demand forecasts are adjusted for demand side management initiatives and impacts of larger embedded generating units.

### *7.1.1 Linear regression methodology*

The individual connection site forecasts are based upon linear regression methodology.

### *7.1.2 Temperature correction*

Historic data is weather temperature corrected based upon Bureau Of Meteorology (BOM) temperature information across weather sites closest to each connection site.

### *7.1.3 Embedded generation*

The impact of individual larger embedded generating units on connection site forecasts is only subtracted from the base-line load demand forecasts when the generator would be normally operating at the time of maximum demand on the relevant distribution zone substation or the transmission connection site. As such, for a single embedded generator within a geographical area its unavailability is not allowed for if outside its normal operation.

Should the situation arise where multiple embedded generators operate normally at time of local geographical area maximum demand, a probability based allowance will be made for generating unit unavailability.

The impact of multiple small-scale embedded generation, such as photo-voltaics, is included in that the contribution is an inherent part of historic connection point demands.

## 7.2 Application to the Capacity Management Levels

The DF is a primary driver in the identification of emerging distribution system limitations and requirements for augmentations.

### *7.2.1 Major System*

This level of work activity incurs substantial project capital expenditure and as such Regulatory Tests are applicable in the majority of cases requiring DF data as part of the analysis of the solution.

This process has been applied through the current regulatory control period (2007/2008 to 2011/2012) and will continue for the next period.

### *7.2.2 HV System*

This level of work activity can incur high levels of project capital expenditure and in some cases Regulatory Tests are applicable. Where this is undertaken the analyses use DF data.

At lower levels of project capital expenditure the DF is used to extrapolate HV feeder loadings based upon the source substation forecast. The feeder demands are analysed to identify emerging HV System limitations and the timing of required additional feeders.

This process has been applied through the current regulatory control period (2007/2008 to 2011/2012) and will continue for the next period.

### *7.2.3 LV system*

Due to the lower levels of project capital expenditure individual distribution substations load is assessed based on the source substation DF over the forthcoming 5-year period. This identifies distribution substations limitations by unit and year.

This process has been applied for 2010 load data to forecast requirements for the next regulatory control period.

# 8. RISK BASED MANAGEMENT

For capacity related work there is a high correlation between creation and augmentation of system assets and the treatment of network risks. The following sections describe the main processes that are used to identify capacity system risks, methodologies that are used to address the higher risks and options that are undertaken to apply treatment.

As each of the processes is targeted to each of the three levels of system management the risks may be similar but treatment is varied according to the elements addressed.

## 8.1 Risk Level Evaluation

The network capacity related risks have been assessed, for the system as a whole, according to the Aurora Risk Management Framework. The Aurora Risk Management Matrix used in evaluating the level of untreated risk is shown in Appendix A.

The risk levels used in the framework are:

1. Low;
2. Moderate;
3. High; and
4. Extreme.

The analysis, as shown in , portrays the level of risk associated with each of the three levels of capacity management should capacity risks go untreated through augmentation or other solutions.

**Table 1: Capacity risk matrix**

| HIGHEST RISK IF LEFT UNTREATED | CAPACITY MANAGEMENT LEVEL | | |
|---|---|---|---|
| | MAJOR SYSTEM | HV SYSTEM | LV SYSTEM |
| Human safety, both public and internal | High | High | High |
| Environmental | Moderate | Moderate | Moderate |
| Business or legislated standards | Moderate | High | Low |
| Customer outcomes | Moderate | Moderate | Moderate |
| Community values and expectations | Moderate | Moderate | Moderate |
| Financial | Moderate | Moderate | Moderate |
| Loss of equipment life | High | Moderate | Moderate |
| System stability / security | High | Moderate | Moderate |
| Quality of supply | Moderate | Moderate | Moderate |
| Operability of the system components | High | Moderate | Moderate |

Individual assessments for each level are contained in Reference 3.

## 8.2 Risk Assessment & Treatment

The generic process for assessment of risks and the identification, evaluation and implementation of treatment options can be illustrated by the process shown in Figure 2.

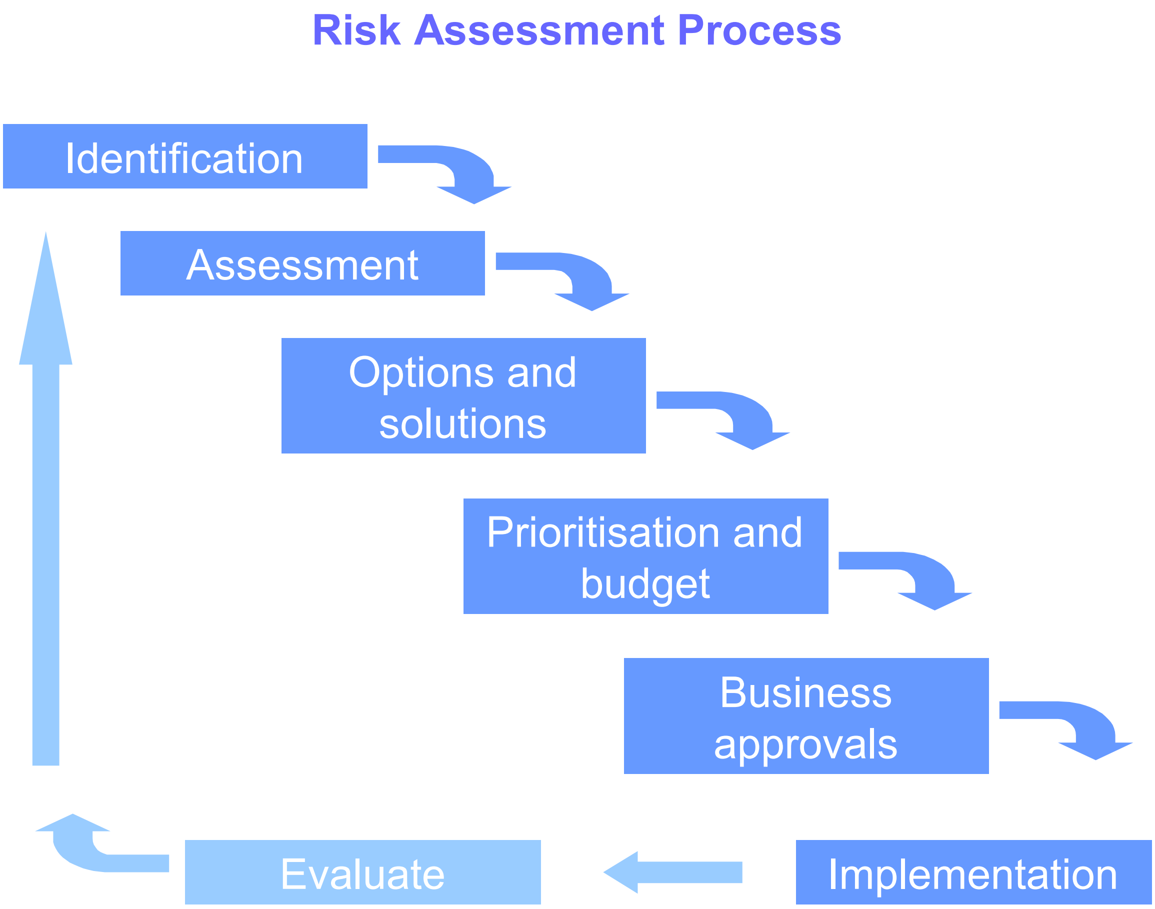


**Figure : Risk Assessment Process**

## 8.3 Risk Identification

As outlined above, network capacity related risks have been assessed according to the Aurora Risk Management Framework and the following expands on the categories listed in Table 1.

- Human safety both public & internal:
  - Decreased operating clearances
  - Increasing risk of third party contact
  - Electric shock or electrocution
  - Explosion,
  - Physical damage or harm.
- Environmental incidents:
  - Increased risk of conductor clashing or failure leading to interruptions and fire ignition
  - Explosion and expulsion of oil
- Business or legislative standards:
  - Non-compliance with obligations

  - fine, breach of code and standard or licence for TEC, NER, connection agreements, legislation and regulation;
  - Failure of asset.
- Customer outcomes:
  - substandard reliability (SAIFI and SAIDI)
  - unavailability of network services
  - inability to meet obligations to connect
- Community values and expectations
  - Increased customer complaints
  - reputation damage
- Financial:
  - higher cost associated with repairing equipment under fault, compensation payments, under regulatory regime - STPIS outcomes;
- Loss of equipment life
  - decreased life expectancy of assets due to operating above design criteria
  - overheating of transformers and switchgear leading to:
    - flashover
    - explosion
    - oil spill
    - reduced current ratings
- System stability / security
  - running the system in an unsecure state or above its capability that may lead to consequential failures
  - protection operation initiated interruptions to supply
  - rotational interruptions to supply to manage equipment loadings
- Quality of supply
  - electromagnetic interference
  - damage to network and customer equipment
  - increased customer complaints
  - protection operation initiated interruptions to supply
- Operability of reticulation and system components
  - Reduced capability to minimise impacts of
    - planned outages
    - contingency events
  - sub optimal system design and / or equipment that cannot be operated.

### 8.4 Risk Assessment

The following are assessed to gain and understanding of the risks and to enable the evaluation of treatment options:

- Causative issues;
- Identification of magnitude and breadth of the issue; and
- Implication of not addressing the issue.

## 8.5 Options and Solutions

A suite of options is developed that will address the identified issue(s). Each option is assessed for treatment of the issue with consideration to its implementation, probability of success, business fit and financial requirements.

Some projects are jointly attended with Transend. Options can be covered in the Distribution Annual Planning Report (DAPR) and its review.

Larger projects are subjected to the NER Regulatory Test process or Regulatory Investment Test for Transmission (RIT-T) where undertaken jointly with Transend.

The management of risk may require treatment by any of the following options:

| | | |
|---|---|---|
| 1. | Removal from service | Involves removal of the asset in its entirety. Normally does not extend to conductors or transformers, given that if the component is heavily loaded it is needed, but can be associated with switches or other control devices. |
| 2. | Reduction in loading | Involves redirection of circuit loading to other circuits or units. Non-network solutions such as Demand Side Management and Embedded Generation are considered in this context. |
| 3. | Augmentation | Involves making the device stronger, bigger or replicated or addressing quality of supply issues. |
| 4. | Do nothing | No action to be undertaken. |

In investigating risks and identifying and evaluating treatment options consideration of the capability of assets is given in the following terms:

| | |
|---|---|
| Planning rating | A nominal rating based upon design ambient temperature, wind speed, insolation or nameplate rating. |
| Cyclic rating | Based upon core hot spot temperature not exceeding design criteria and thermal loading over a 24 hour period. |
| Nameplate rating | The rating identified upon the equipment nameplate for normal operation |

In addition to specific considerations applicable to each of the Capacity Management Levels, the following are common to all levels and aid the assessment of the level of untreated risk and action undertaken to treat any identified risk:

| | |
|---|---|
| Safety | People must not be endangered by the operation of Aurora equipment or as a consequence of operating the system. |
| Subtransmission, High Voltage & Low Voltage circuits | Subtransmission circuits should be operated with due regard to the cyclic rating of the asset or suite of assets. This enables clearances to ground or other electrical structures to be safely maintained and components not to be unduly stressed e.g. connectors and fittings. |
| Switchgear | Switchgear should be operated with due regard to the rating of the asset or suite of assets. This enables components not to be unduly stressed causing mal-operation. |
| Transformers | Transformers should be operated with due regard to the cyclic rating of the asset or suite of assets. This enables components not to be unduly stressed and the transformer life expectancy not to be unduly shortened by its operation. |
| Customer outcomes | Interruptions and quality of supply are maintained so to not adversely affect the level of contracted supply. |
| Environmental | Relevant environmental standards are to be employed including Electro Magnetic Radiation (EMR) and noise.<br>One of the higher risks is the expulsion of oil due to transformer failure. Management of load mitigates the consequence. |
| Standards | Relevant standards are to be complied with. Common standards used are:<br>1. Environmental Protection and Biodiversity Conservation Act 1999;<br>2. Environmental Management and Pollution Control Act 1994;<br>3. Electricity Wayleaves and Easements Act 2000;<br>4. Land Acquisition Act 1993;<br>5. AS/NZ 61000 Electromagnetic Compatibility (EMC) parts 3.6 & 3.7;<br>6. AS 2374.7 Power transformer loading -1997<br>7. AS/NZ 3000 Electrical installations (known as the |

| | |
|---|---|
| | Australian/New Zealand Wiring Rules)<br>8. ENA CB(1) 2006;<br>9. AS 2067 Substations and High Voltage installations exceeding 1kV ac;<br>10. TEC<br>Chapter 8 sections 3, 6, 7 & 8; and<br>11. NER<br>Sections 4.2, 4.6, 5.3, 5.5, 5.6,<br>Schedules 5.1, 5.2, 5.3, 5.4, 5.5, 5.7. |
| Community values and expectations | The visibility and amenity of any infrastructure installed. Community reaction and appropriate consultation where necessary and the installation of equipment being undertaken with due regard to community values. |
| Loss of equipment life | Larger and more expensive infrastructure is to take into account loss of equipment life due to loading beyond nameplate ratings. This should mainly focus on power transformers and underground cables. |
| System stability | Loading beyond nameplate ratings and system design requirements will introduce elements of system instability and possible consequential supply loss and equipment failure. |
| Operability of components | Loading beyond nameplate ratings will cause reduction of operation capability e.g. switch contacts either welding shut or not being able to be closed. This has consequences of the component and the system being unable to be operated in its optimal state to ensure a reliable and quality outcome. |
| Fault rating | The designated fault rating for the component should not to be exceeded. Conditions to be assessed are steady state and transient modes of operation. |
| System voltage | System voltage output should be contained within its permitted range. |

### 8.6 Prioritisation and Budget

An economic cost effectiveness analysis of possible options is carried out to identify options that meet the regulatory test. Budgets are refined and year of implementation identified.

Prioritisation takes account of:

1. Severity of the untreated risk;
2. Impact upon the business if left untreated;
3. Time of requirement;

4. Capital finance constraints; and
5. Business appetite.

### 8.7 Business Approvals

The identified treatment option is approved according to the level of required expenditure conforming to the business delegation approval process.

### 8.8 Implementation

The project(s) are planned, designed and commissioned.

### 8.9 Evaluation

Following implementation of the solution to treat the risk, the project(s) is evaluated to confirm that the treatment has reduced the level of risk to an acceptable level.

Should the treatment option be unsuccessful the issue is reviewed and the planning process entered again.

## 9. MAJOR SYSTEM CAPACITY RISK MANAGEMENT

The methodology outlines the generic components for the Major System activities as shown in Figure 3.

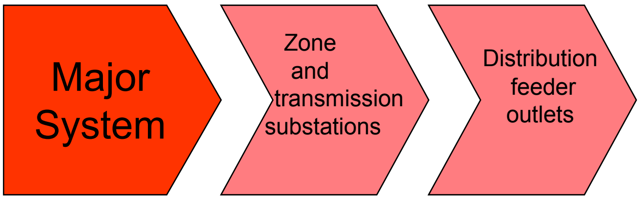


**Figure 3: Major system activities**

This process is undertaken as part of the Annual Planning Review (APR) and system joint planning with the Transend where it involves Aurora's Major System components.

This process covers work associated with creating or augmenting both Aurora zoner substations and Transend substations providing connection points for Aurora.

Aurora's scope covers:

1. Zone substation building and equipment;
2. Acquisition of land;
3. Subtransmission connections;
4. HV feeder tails;
5. System HV reconfigurations;
6. Distribution substation voltage tapping change; and
7. Changing equipment for a higher fault level.

Where this involves Transend substations, the Aurora activities are:

1. HV feeder tails;
2. System HV reconfigurations;

3. Distribution substation voltage tapping change; and
4. Changing equipment for a higher fault level.

The overall objective of this level of the process is to treat risks proportionally by:

1. Maintaining necessary level of network security;
2. Providing adequate network capacity and transfer capacity;
3. Managing compliance against standards and business requirements; and
4. Maintaining appropriate voltage levels and quality of supply at the point of supply.

## 9.1 Risk Identification

The following Major System network element attributes are a means of identifying the varying degrees of the risk associated with specific infrastructure. The articulation of the level of assessment (e.g. 110%) has been made based upon Aurora's understanding of where the level of assessment has an adverse effect upon an asset.

Specific attributes for assessment are:

- Subtransmission circuits
  - 100% to 110% of planning rating;
  - 110% to 120% of planning rating;
  - Above 120% of planning rating;
- Transformer cyclic loading
  - 100% to 110% of nameplate rating;
  - 110% to 120% of nameplate rating;
  - 120% + of nameplate rating;
- Station HV switchboard peak loading
  - 100% to 120% of nameplate rating;
  - 120% of nameplate rating;
  - Reactive power management;
  - HV system ties or interconnections;

## 9.2 Considerations Employed

The following are specific Major System considerations that are used in aiding the assessment of the level of untreated risk and action undertaken to treat any identified risk:

**Financial** Appropriate financial analyses to be undertaken in option assessments. Type and number of infrastructure to be prudent i.e. two units when one is required. Deferment and all credible options to be incorporated into the planning of projects. Reinforcement of the system is to be undertaken to defer large capital outlays.

**System stability** N-1 or group firm transformation is to be considered to enable appropriate security of the system to be maintained.

## 9.3 Additional Processes

In most cases it is necessary that Transend is engaged in the delivery of options and solutions at the Major System level. This process, known as 'joint planning', enables impacts of major activities to be assessed from the wider system viewpoint.

As a requirement of the NER (section 5.6) major expenditures are to use the Regulatory Test assessment process to establish the optimum risk treatment. Projects that exceed the prerequisite threshold expenditure are assessed either under the RIT-T or Regulatory Investment Test Distribution (RIT-D) upon change to the NER, as proposed by the Australian Energy Market Commission (AEMC).

Regulatory investment tests mandate the need to perform analyses of all credible options including non-network solutions. Non-network solutions are typified as not requiring network infrastructure to meet the risk.

Such solutions may be:

1. Provision of third party generation;
2. Installation of capacitor banks;
3. Peak load shifting;
4. Reduction in electrical load by negotiating demand from the consumer;
5. Curtailment of electrical demand; and
6. Greater asset utilisation.



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# 10. HIGH VOLTAGE SYSTEM CAPACITY RISK MANAGEMENT

The methodology outlines the generic components for the High Voltage system activities as shown in Figure 4.

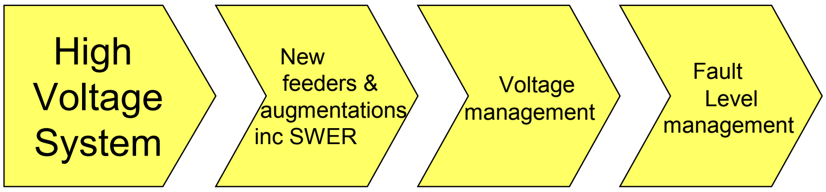



**Figure 4 HV system processes**

The overall objective of this level of the process is to treat risks proportionately by:

1. Managing network feeder loading;
2. Providing adequate network transfer capacity;
3. Providing adequate levels of (high) voltage;
4. Managing system power factor;
5. Managing system Fault Levels;
6. Managing compliance against standards and business requirements and
7. Maintaining appropriate voltage levels and quality of supply at the point of supply.

### 10.1 Risk Identification

The following High Voltage System network element attributes are a means of identifying the varying degrees of the risk associated with specific infrastructure. The articulation of the level of assessment e.g. 110% has been made based upon Network understanding of where the level of assessment has an adverse effect upon an asset.

- Feeder cyclic loading (overhead conductors)
  - 100% to 110% of thermal rating
  - 110% to 120% of thermal rating
  - 120% to 130% of thermal rating
- Feeder cyclic loading (underground conductors – paper lead conductors)
  - 100% to 110% of thermal rating
  - 110% to 120% of thermal rating
  - 120% to 130% of thermal rating
- Feeder cyclic loading (underground conductors – XLPE conductors)
  - 100% to 110% of thermal rating
  - 110% to 120% of thermal rating
  - 120% to 130% of thermal rating
- Voltage regulation
  - 95 % to 94% of nominal voltage
  - 94% to 93% of nominal voltage
  - below 93% of nominal voltage
- Voltage regulation transformers cyclic loading
  - Up to 130 % of nameplate rating
  - 130% to 150% of nameplate rating
  - 150% plus of nameplate rating
- Switch loading over 100 % of the nameplate rating; and
- System ties or interconnectors.
- Fault level

### 10.2 Considerations Employed

The following are specific High Voltage System considerations that are used in aiding the assessment of the level of untreated risk and action undertaken to treat any identified risk:

| | |
|---|---|
| **Financial** | Reinforcement of the system may be undertaken to defer large capital outlays. Projects that may be deferred are to be incorporated into future planning. |
| **System stability** | The HV feeder system is run as N security. N-1 switched is considered for security and reliability but will involve interruption(s), which may be prolonged, to return to a stable or manageable operating state. |

## 10.3 Additional Processes

Non-network solutions are typified as not requiring network infrastructure to meet the risk. These are covered in the Demand Management Plan.

Such solutions may be:

1. Provision of third party electrical generation;
2. Reduction in electrical load by negotiating demand from the consumer e.g. Bruny island development;
3. Curtailment of electrical demand, and
4. Greater asset utilisation.

## 10.4 Work Programs

### *10.4.1 Conductor Augmentation*

***Avoca***

Reinforce the network to manage inter-connectability, reliability and load.

***Chapel Street***

Reinforce the network to manage reliability and load.

***Hobart Subtransmission***

Augment East Hobart and West Hobart zoned substations subtransmission to manage load.

***Mowbray***

Reinforce the network to manage reliability and load.

***North Hobart***

Reinforce the network to manage reliability and load.

***Palmerston***

Reinforce the network to manage load associated with irrigation supplies.

***Sandford***

Reinforce the network to manage reliability, inter-connectability and load. Enables further deferment of Sandford zone.

***Westbury***

Reinforce to extend the feeder network to enable the deferment of the Westbury substation.

***Railton***

Reinforce to extend the feeder network to enable the deferment of Westbury substation.

***Devonport***

Reinforce the network to manage load.

***Ulverstone***

Reinforce the network to manage load.

***George Town***

Reinforce the network to manage load.

***Smithton***

Reinforce the network to manage reliability and load.

***Launceston***

Reinforce the network to manage load.

***St Marys***

Reinforce the network to manage load.

***Ulverstone***

Reinforce the network to manage load.

***Geilston Bay***

Reinforce the network to manage load.

***Sandy Bay***

Reinforce the network to manage load.

***Chapel Street***

Reinforce the network to manage load.

***Bridgewater***

Reinforce the network to manage load.

***Wynyard***

Reinforce the network to manage load.

### *10.4.2 Embedded Generators*

Reinforcement of the system associated with new embedded generators coming on to the feeder network. The work is covered in this area is not customer work as this work is issued under a separate scope of works.

### *10.4.3 DINIS API UG*

Grouped work arising from load flow studies associated with over loaded elements of the high voltage feeder network. These have been identified as being beyond their planned ratings and upgrades are necessary.

### *10.4.4 DINIS API OH*

Grouped work arising from load flow studies associated with over loaded elements of the high voltage feeder network. These have been identified as being beyond their thermal ratings and upgrades are necessary.

### *10.4.5 Regulators*

Augmentation is based upon load.

### *10.4.6 Voltage support*

Other than the regulators, capacitor banks are used. These have been identified for feeders where there is poor power factor or poor voltage regulation.

### *10.4.7 Operation*

***HV Phasing***

In Devonport and Burnie area there exists a number of locations where Aurora's high voltage equipment is not in phase with the adjacent equipment. This causes extra work to reconfigure or maintain the system and has an adverse effect on reliability as all operations have to break-before-make operation. This work covers remediation of those components of the network.

***Switching***

In the southern networks there are a number of tee-jointed HV cables. Over time these have become problematic due to a higher requirement to maintain reliability and alterations to the systems causing cascaded interruptions. This work is to remediate those HV networks to enable ring main substation connections enabling flexibility in operating.

***Transfer***

This work enables better transfer of high voltage load across the network to facilitate management of feeder loading. This also has an additional benefit of having a more flexible high voltage network that enables higher reliability and better security.

***Security***

This work covers the security of large towns and Burnie city. The intent of the Burnie work is to provide transfer capability to manage security risk by loss of transmission substation element. The work entailed at Burnie being a 11kV system within a 22kV supply area means that supply transfers are difficult. Analysis is being conducted to ascertain level of interconnections required. The budget indicated in the program is indicative of anticipated actions required.

The other area of security is Primrose Sands / Connelly's Marsh. This work is to provide alternative supply to Primrose Sands. Primrose is a large beachside area with a long radial link.

### *10.4.8 Development*

#### *Droughty Point*

Reinforce the network to manage reliability and load associated with sub division development

#### *Hobart*

This work is to shift load from terminal substations Creek Road to Risdon. This will balance the load on the 33kV sub transmission network. Creek Road is forecast to become overloaded.

#### *Westbury*

Entails development of a 22kV feeder from Hadspen sub station to supply the Westbury area. Westbury area has become an industrial hub and anticipated customer loading is such that the system will not be satisfactorily supplied of the existing network into the future. This work will also defer major expenditure of Westbury sub station that is a joint planning project with the Transend. Westbury substation is forecast to be required in 2017. This work is to defer that requirement.

#### *Knights Road*

This work is to provide a new feeder from Knights Road sub station into the Huonville township. It is forecast to be required in 2013 / 14 based upon present load forecast.

#### *Chapel Street*

This work is to relieve loading conditions on the existing HV feeder network.

#### *LGA works*

This work covers the opportunity of working in conjunction with the Local Government Authority by the placement of ducting in road works under constructions.

#### *Thermocouples*

This work will cover staged programs to install temperature monitoring equipment in feeder ducts exiting zone and terminal substations. This will enable a more accurate assessment of loading conditions of the HV feeder cables, which will enable a better utilisation of the network.

### *10.4.9 Conversion*

#### *Gretna*

Covers a staged augmentation of the 11kV network in the Gretna area to a 22kV system. This defers load off New Norfolk 11kV zone substation and transfers this on to New Norfolk 22kV terminal substation. It also has the benefit of transferring irrigation load, which are problematic with starting currents and consequent power quality problems.

Further, this enables increased utilisation of the network with all transfers will be at 22kV. At present load cannot be transferred between 11kV and 22kV and this has impacts on reliability and operational flexibility.

#### *Richmond Area*

This is a staged augmentation of the existing 11kV network in the Richmond area to a 22kV system. There are two main strategies associated with Richmond.

*Reduction of footprint and load of 11kV system*

Projects are to migrate existing 11kV areas in the rural areas of the network, onto the 22kV Sorell system. The benefit is to manage the irrigation load, which is problematic with motor starting currents and consequent power quality problems. It also enables higher utilisation on the 22 kV network as transfers can be readily undertaken. At present load cannot be transferred between 11kV and 22kV and this has impacts on reliability and operational flexibility.

*Upgrade of Richmond zone substation*

Refer to section 9.4.3.

#### *Westerway*

These are the last stages of the Westerway conversion. These conversions work in conjunction with those of Gretna conversions. This also has the benefit of eliminating the condition-based replacement of the Westerway zone substation, which will become redundant under this arrangement. This enables better utilisation of the network with transfers being at 22kV. At present load cannot be transferred between 11kV and 22kV and this has impacts on reliability and operational flexibility.

### *10.4.10 SWER (12.7 kV)*

#### *Blessington*

This SWER system has been identified as being over 100KVA loading. This is the last stage of replacement of the SWER to multi-phase distribution. There are remaining sections that are not intended to be upgraded.

#### *Mathina*

This SWER system has been identified as being over 100KVA loading within the next regulatory control period. This is the second of stage 2 replacement of the SWER to multi-phase distribution. There is anticipated to be no further stages.

### *Reedy Marsh*

This SWER system has been identified as being over 100KVA loading. This is the last stage of replacement of the SWER to multi-phase distribution. There are remaining sections that are not intended to be upgraded.



## 11. LOW VOLTAGE SYSTEM CAPACITY RISK MANAGEMENT

The methodology outlines the generic components for the Low Voltage system activities as shown in Figure 5.

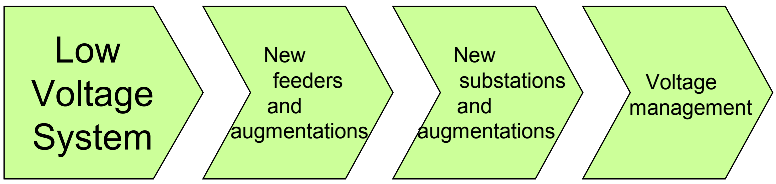



**Figure 5: Low Voltage System processes**

The overall objective of this level of the process is to treat risks proportionality by:

1. Managing necessary level of network transformer and low voltage feeder loading;
2. Providing adequate network low voltage transfer capacity for maintenance and emergency purposes;
3. Managing system power factor;
4. Managing compliance against standards and business requirements; and

5. Maintaining appropriate voltage levels and quality of supply at the point of supply.

### 11.1 Issue Identification

The following Low Voltage System network element attributes are a means of identifying the varying degrees of the risk associated with specific infrastructure. The articulation of the level of assessment e.g. 110% has been made based upon Aurora's understanding of where the level of assessment has an adverse effect upon an asset.

Attributes for assessment are:

- Transformer 2 hour peak cyclic loading
  - 100% to 110% of nameplate rating
  - 110% to 120% of nameplate rating
  - 120% to 130% of nameplate rating
  - Over 130% of nameplate rating
- Feeder thermal loading (overhead)
  - 100% to 110% of thermal rating
  - 110% to 120% of thermal rating
  - Over 120% of thermal rating
- Feeder thermal loading (underground – paper/ lead)
  - 100% to 110% of thermal rating
  - 110% to 120% of thermal rating
  - Over 120% of thermal rating
- Feeder thermal loading (underground - XLPE)
  - 100% to 110% of thermal rating
  - 110% to 120% of thermal rating
  - over 120% of thermal rating

Voltage regulation outside of 226 to 254 volts;

- Power quality eg flicker, waveform distortion; and
- LV circuit ties.

### 11.2 Considerations Employed

The following are specific Low Voltage System considerations that are used in aiding the assessment of the level of untreated risk and action undertaken to treat any identified risk:

| | |
|---|---|
| **Safety** | With low voltage equipment there is more equipment employed in urban areas arising from increased load density. As a consequence there is a higher probability of risk to the public from the increased density of low voltage assets. |

**Transformers**

AS 2474.7 Loading guide for oil immersed transformers is used to assess cyclic loading of transformers.

Studies of transformers reveal that:

- Approximately 9,300 transformers are of a size (>= 100 kVA) that warrants scrutiny of loading due to the relatively high costs of replacement, the negative effect upon public and operator safety and the reliability being delivered to the customer base. Larger transformer sizes have a proportionally higher customer connection and are in denser load areas.
- Approximately 20,900 transformers (<100 kVA) are available to be strongly loaded. These are predominately pole mounted and in rural areas serving small customer numbers. In urban areas there are some with limited integrated LV circuits. Present processes manage power quality and reliability outcomes.

A ground-mounted substation by its nature is more expensive than pole mounted equipment. It takes greater business effort to install and maintain such equipment. As a result activities on system infrastructure are assessed more rigorously. Following considerations of safety and quality of supply the loading of the transformer can be greater than its nameplate rating by up to 130 to 150%.

Pole mounted substation are more numerous and per unit less expensive that their ground-mounted equivalents. Most pole-mounted substations are less than 100 kVA in power rating and serve less than 50 customers. Following considerations of safety and power quality the cyclic loading of the transformer can be over 150% of its nameplate rating.

As a result of legislated requirements, in particular AS/NZ 3000, all transformer upgrades require each site to be brought to current standard, including bunding, clearance etc. This affects the work associated with ground mounted substations in particular.

**Circuit analysis** Low voltage circuits whether overhead or underground are governed by the same guiding principles. As conductors have low thermal inertia this means that currents in excess of the rating will cause irreparable damage. This damage manifests itself in failure of conductor or joints, loss of supply to customers and below standard voltage at the customers' premises.

6.

**System stability** The LV feeder system is run as N. N-1 is considered for security and reliability but will involve interruption(s), which may be prolonged, to return to a stable or manageable operating state.

## 11.3 Additional Processes

Non-network solutions are typified as not requiring network infrastructure to meet the risk. These are covered in the Demand Management Plan.

Such solutions may be:

1. Provision of third party electrical generation;
2. Reduction in electrical load by negotiating demand from the consumer e.g. Bruny island development;
3. Curtailment of electrical demand; and
4. Greater asset utilisation

## 11.4 Work Programs

### *11.4.1 Distribution Substations*

The program over the 2012 to 2017 regulatory control period plans to upgrade the following to relieve unacceptable overload:

1. 16 units or approximately 3 units per annum ground mounted substations of 300kVA rating. Annual budget cost $450k;
2. 104 units or approximately 21 per annum pole mounted substations of 63kVA rating up to 300kVA. Over the forthcoming regulatory control

period the augmentations planned represent approx 1.2% of the fleet of transformers of this size. The Annual budget cost $1.04M; and

3. 42 units or approximately 7 per annum pole mounted substations of 50kVA rating and below. Over the forthcoming regulatory control period the augmentations planned represent approx 0.2% of the fleet of transformers of this size. Annual budget cost of

The volumes have been identified from listings of substation loads and the units prioritised based upon maximum loading i.e. over 150% of nameplate rating.

The AS/NZ 3000 wiring rules have a significant effect upon the augmentation of substations. To comply with this standard, augmentations preclude upgrading only the transformer and necessitates the complete rebuild of the substation.

### *11.4.2 Low Voltage Networks*

The program over the 2012 to 2017 regulatory control period has allowed for works associated with low voltage conductor upgrades. This is unspecified work and relates to minor upgrades associated with winter peak loading conditions or other times as loading conditions dictate.

## 12. RESPONSIBILITIES

Maintenance and implementation of this management plan is the responsibility of the Thread Leader – System Development.

Approval of this management plan is the responsibility of the Group Manager Network Development.

## 13. REFERENCES

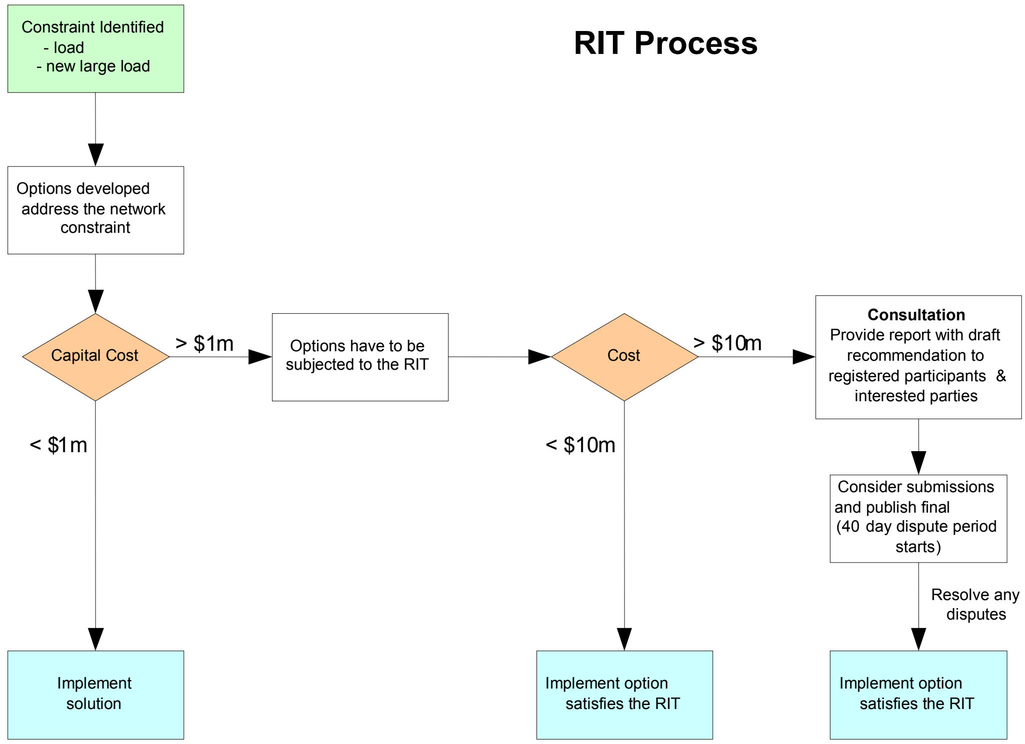
1. Capacity management plan risk assessment tables - NW30143279
2. Aurora Energy 2010 Demand Forecast NW30167668, 30 167689 & 301676870
3. Capacity management risk assessment tables (NW30143279)

# Appendix A Aurora Risk Management Matrix

| | | | Severity | | | | |
|---|---|---|---|---|---|---|---|
| | | Definition | The impact can be dealt with by routine operations. | The impact would threaten the ability of Aurora to achieve current year objectives. | The impact would threaten the ability of Aurora to meet its strategic objectives in the short term | The impact would threaten the ability of Aurora to achieve its strategic objectives in the medium term | The impact is beyond Aurora's ability to manage o resource and as such threatens the survival of the company. |
| | Definition | | **1 Low** | **2 Medium** | **3 High** | **4 Very high** | **5 Extreme** |
| **Likelihood / Probability** | Is expected to occur in most circumstances | **5. Almost certain** | Moderate | High | Extreme | Extreme | Extreme |
| | Will probably occur in most circumstances | **4. Likely** | Moderate | High | High | Extreme | Extreme |
| | Might occur at some time | **3. Possible** | Low | Moderate | High | High | Extreme |
| | Could occur at some time | **2. Unlikely** | Low | Low | Moderate | High | High |
| | May occur only in exceptional circumstances | **1. Rare** | Low | Low | Low | Moderate | Moderate |

| | | |
|---|---|---|
| Extreme: | Immediate action required | Treatment Plan required |
| High: | Senior management attention required | Treatment Plan required |
| Moderate: | Management responsilbility must be specified | |
| Low: | Manage by routine procedures | |

# Appendix B Regulatory Investment Test Process




Steps undertaken to meet the regulatory test requirements (AER v3.0):

1. Extent and timing of the need to address the network limitation defined, including identification and assessment of any deferral works;
2. Options developed and costed to address the network limitation;
3. Present value analysis of the options undertaken;
4. Sensitivity anal ysis under taken, taking i nto ac count v ariation i n l oad forecast, costs, etc;
5. Consultation r eport w ith dr aft r ecommended ac tion an d i nvitation for submissions published (application notice to AEMO);
6. Submissions considered and Final Report published;
7. 40 day dispute period; and
8. Recommended option progressed.