Appendix 1.18: Network augmentation standard

Regulatory proposal for the ACT electricity distribution network 2019-24
January 2018

Disclaimer: On 1 January 2018, the part of ActewAGL that looks after the electricity network changed its name to Evoenergy. This change has been brought about from a decision by the Australian Energy Regulator. Unless otherwise stated, ActewAGL Distribution branded documents provided with this regulatory proposal are Evoenergy documents.

evoenergy

ASSET STRATEGY
Distribution Network Augmentation Standard
SM1197

Contents

1. Purpose

The purpose of this standard is to define the distribution network augmentation criteria for ActewAGL's distribution network planning and expansion.

2. Scope

The scope of this document includes standards and targets that ActewAGL aims to comply with and the criteria to be adopted. The following key targets and criteria are set in this standard:

1. Network Supply Security Standard,
2. Network Performance Standards and Reliability Targets, and
3. Rating Standard, Loading Limits and Augmentation Criteria.

This standard mainly applies to the review of ActewAGL's distribution network load forecast and network capacity, to identify emerging constraints and to develop a ten year augmentation plan including network augmentation programs and projects.

3. Objectives and planning approach

The planning and development process for both transmission and distribution networks, is carried out in accordance with the National Electricity Rules (NER) Chapter 5 Part B Network Planning and Expansion. Planning for the transmission network is carried out in accordance with the NER Section 5.12 Transmission annual planning process and for the distribution network in accordance with the NER Section 5.13 Distribution annual planning process.

The primary objective of planning is to ensure that customers are able to receive a sufficient and reliable supply of electricity now and into the future. ActewAGL's planning standards are set to ensure that peak demand can be met with an appropriate level of backup should a credible contingency event occur. A credible contingency event is the loss of a single network element, which occurs sufficiently frequently, and has such consequences, as to justify ActewAGL to take prudent precautions to mitigate. This is commonly referred to as an N-1 event. Typically there is a high level of redundancy applied to electricity networks. This reflects the implications of network service failures, noting that communities and businesses have a low tolerance to electricity supply interruptions.

ActewAGL's planning standards are determined on an economic basis but expressed deterministically. ActewAGL uses probabilistic planning techniques when carrying out economic analysis. When assessing the economic benefits of a proposed solution to an issue, we calculate the probability of an event occurring that would result in an interruption of supply to customers. This probability is used as part of the economic analysis to determine whether the benefits of the proposed solution exceed the costs. For example if the supply demand to a part of the network could not be met fully in the event of a contingency, existing assets may be upgraded or new assets may be installed if justified economically. Changes to system losses are included in the economic evaluation of a project.

The early identification, consultation and monitoring of emerging network limitations and prospective network developments is aimed at providing proponents of non-network solutions adequate time to prepare proposals.

ActewAGL's planning approach to addressing load growth or network constraint issues, is to use probabilistic analysis techniques coupled with fully exploring non-network solutions such as demand-side management, before investing in network augmentation. This approach takes into account the combination of demand forecasts, asset ratings and asset failure rates to identify the severity of constraints and the required timing of solutions.

ActewAGL runs a load flow model of the network using a computer software program known as ADMS (Advanced Distribution Management System). This system is linked to our Supervisory Control and Data Acquisition (SCADA) system and obtains and analyses data such as the status of network assets (e.g. positions of circuit breakers), current flows and voltage levels throughout the network, in real time. This system is used to identify issues such as power flow constraints or voltage level issues on the network, and is used to model what-if scenarios such as the effect of a new load or generation connection. Using this tool, ActewAGL is able to identify existing and emerging constraints which form the basis of our asset management and network development plans.

ActewAGL's planning process is an annual process and covers a minimum forward planning period of ten years. The process commences with a comprehensive analysis of all indicators and trends to forecast the future load on the network. A detailed analysis of the network is then carried out to identify performance and capability shortcomings, i.e. constraints.

ActewAGL uses a two hour emergency cyclic rating for all its zone substation power transformers. ActewAGL has adopted the use of two hour emergency ratings and normal cyclic ratings, and uses the ADMS system to regularly record and reassess the cyclic loading capability of zone substation equipment, based on equipment manufacturer's recommendations and relevant Australian and international standards. ActewAGL maintains a high level of zone substation power transformer utilisation by using the two hour emergency cyclic rating, and effective load balancing between zone substations wherever possible. Load balancing is an integral initial solution to network augmentation planning.

ActewAGL ensures the following prior to committing to any large investment:

- Investments are cost effective and consider whole-of-life costs associated with a new asset.
- Timing of the new investment is such to meet the requirement of the need when it reaches the point that the need cannot otherwise be met.
- Appropriate investment procedures are followed, including business case and Board approval, and execution of RIT-T or RIT-D if required.
- Works are timed to ensure smooth capital and replacement cash flows, and availability of resources.
- Works are coordinated as required with other utilities and/or network service providers, and to meet customer needs.

3.1 Deterministic versus probabilistic planning approaches

Planning requirements are generally set as "deterministic" requirements, where rules or standards require investment to meet N (or N-0), N-1 and N-2 contingency criteria, where "N" is a single infrastructure element such as a transformer, transmission line or cable. These criteria basically define the level of reliability and security to which a network is designed. These requirements are intended to ensure that the network can withstand periods of plant outage, without leading to load shedding. The strict use of deterministic planning criteria that consider only supply side options, however, may preclude demand side management options.

Under the “deterministic” planning approach, the timing of augmentations is determined on the basis of peak demand exceeding the planning criteria. If the deterministic planning approach is applied strictly, network investment to augment capacity would be required prior to the year when peak demand exceeds capacity. Deterministic criteria like N-1 and N-2 also assume that network investment occurs in discrete units, with known levels of reliability. It therefore effectively assumes that investment in infrastructure is used to meet planning criteria. This can be a barrier to demand management as demand management projects are not always available in discrete blocks to balance against network investments in infrastructure such as transformers and line upgrades.

The “probabilistic” planning approach is an extension of the deterministic planning approach in the sense that it provides a method of assessing the economic value of network reliability to customers. This can be used as a way to prioritise competing projects. In doing this, probabilistic planning also provides scope for non-network demand management alternatives to reduce load by introducing the economic value of supply for customers, which is the basis for all demand management projects.

Customers will offer demand response capabilities when the reward for demand response is greater than the value they place on that supply. This can include accepting some degree of direct load control or capacity limitation. Deterministic planning criteria, strictly applied, do not facilitate NSPs offering this type of optimisation decision to customers, as it focuses entirely on the level of reliability and security of supply, not the value of that supply to customers. A probabilistic planning framework therefore may offer a different range of opportunities for demand management. Figure 1 illustrates ActewAGL’s network planning process.

Figure 1: ActewAGL’s network planning process

Planning Inputs and Drivers:

Demand forecasts	Equipment ratings	Load transfer capacity
Security standards	Reliability standards	National Electricity Rules
ACT technical regulations	Quality of supply	Network performance targets
Demand side management criteria	System constraints	Customer load connections
Embedded generation connections	Equipment condition reports	Capital approval process
RIT-T and RIT-D processes	Network augmentation criteria	Design manual
Company policies & standards	Stakeholder obligations	Health & Safety
Financial objectives	Strategic benefits	Legal & Statutory obligations

Planning Process:

Load flow studies	Fault level studies	Network capacity analysis
Identify emerging constraints	Identify credible network options	Identify credible non-network options
Identify power quality improvements	Identify security improvements	Identify network reliability improvements
Joint planning with TransGrid	Options analysis	Carry out RIT-T or RIT-D
Prepare Development Applications	Select preferred options	Prepare business case and project approval
Economic analysis – NPV studies	Risks analysis	Model/simulate network
Load forecasting	Capital approval governance	Customer consultation
Strategic alignment	Security of supply	Financial analysis (NPV)

Planning Outputs:

Programme of Works	RIT-T or RIT-D consultation reports	Annual Planning Report
Zone Substation development reports	Project technical specifications	Capital investment approval
Uprate existing assets	Land access & easement agreements	Demand-side management contracts
Asset renewals & replacements	Tender or contract for procurement	Tender of contract for design & construction
Meet security & reliability standards	Five-yearly regulatory proposal	Build new network infrastructure if required
Regulatory Information Notice	Network modelling	Network augmentation projects
Development Application submissions	Non-network solutions	Customer connections

4. Network Supply Security Standards

This section specifies network supply security standard for each type of network element. The security standard for each category of network asset must meet the standard as set out in Table 1.

Table 1 Network Asset Element Security Standard

Network Element	Security Standard
Transmission Lines	N-1
Zone Substations	N-1
Distribution Substations – Commercial	N
Distribution Substations – Urban Residential	N
Distribution Substations – Rural Residential	N

Network elements with (N-1) security standard must have sufficient capacity to carry the expected maximum load under single contingency condition with no loss of load.

5. Network Performance & Reliability Targets

This section specifies network performance and reliability targets that ActewAGL aims to achieve.

5.1. Network Wide Reliability Indicators

ActewAGL has set the electrical network reliability targets consistent with the requirements of Electricity Distribution (Supply Standards) Code 2000, as listed in Table 2.

Table 2 Network Reliability Targets

Reliability Indicator	Target
System Average Interruption Duration Index (SAIDI)	91 minutes
System Average Interruption Frequency Index (SAIFI)	1.2 interruptions
Customer Average Interruption Duration Index (CAIDI)	74.6 minutes

Where:

- **SAIDI**: System Average Interruption Duration Index. The ratio of total customer minutes interrupted to total customers served. This is a performance measure of network reliability, indicating the total minutes, on average, that customers are without electricity during the relevant period.
- **SAIFI**: System Average Interruption Frequency Index. The ratio of total customer interruptions to total customers served. This is a performance measure of network

reliability, indicating the average number of occasions each customer is interrupted during the relevant period.

- **CAIDI**: Customer Average Interruption Duration Index. The ratio of total customer time interrupted to total customer interruptions. Measured in minutes and indicates the average duration an affected customer is without power. CAIDI = SAIDI/SAIFI.

6. Rating Standard, Loading limits and Augmentation criteria

This section specifies rating standards, loading limits and augmentation criteria for each type of network element in the distribution network. ActewAGL's Electrical Data Manual is the primary source of information for ratings and loading limits for most of the distribution network assets. The Electrical Data Manual provides up to date ratings of the assets.

The continuous (thermal) and emergency operating ratings are specified for all network assets covering each type of network element in the network. These ratings define limit states of an asset and if the forecast demand based on 50% PoE exceeds these ratings for more than a specified duration, then a network constraint is identified. The continuous and emergency ratings are fixed for individual assets and can be reviewed based on an asset specific technical analysis.

The firm rating is specified for all network assets. The firm rating is an operating rating assigned to a network element based on the network asset configuration and the load type. The firm ratings of the assets are adjustable and set at specific levels to ensure the required supply security and network performance is achieved.

6.1. Transmission Lines

6.1.1. Rating Standard

Each individual transmission line is assigned a continuous and emergency rating for summer and winter operations. These ratings are documented in the Electrical Data Manual. The continuous line rating is applicable to normal system operation. The emergency line rating is determined based on the probability of more favourable ambient conditions existing, such as higher wind speed, than is assumed for the continuous rating.

6.1.2. Augmentation Criteria

Transmission line capacity must be augmented if the forecast transmission line maximum demand based on 50% PoE under N-1 conditions is to exceed:

- the continuous rating for more than 1% of the time, or a total aggregated time of 88 hours per annum, or
- the continuous rating by 20%.

Certain events may trigger multiple contingencies, such as a bushfire causing outages of multiple lines in the same corridor. In such cases, the need for transmission line augmentation will be assessed notwithstanding the above criteria.

6.2. Zone Substations

6.2.1. Rating Standard

Each zone substation is assigned continuous and emergency ratings for summer and winter operations and these ratings are documented in the Electrical Data Manual.

6.2.2. Augmentation Criteria

Zone substation capacity must be augmented if the forecast zone substation maximum demand based on 50% PoE under N-1 conditions exceeds the two-hour emergency rating.

Major zone substation augmentation such as the installation of an additional transformer will not be considered until all other options such as load transfer to adjacent zone substations and non-network options have been fully explored and implemented.

6.3. Distribution Feeders

6.3.1. Rating Standard

Feeders in urban areas should have a minimum of two effective feeder ties to meet two-for-three arrangement where it is economically viable, ie two feeders able to supply the load normally supplied by three feeders. A firm rating is assigned to each feeder based on its thermal rating and the number of feeder ties available. The firm ratings of HV feeders are determined according to Table 3.

Table 3 Feeder Firm Rating standard

Feeder configuration	Firm rating as percentage of thermal capacity
Two or more feeder ties	75%
One feeder tie	50%
Feeders operating in parallel	{(N-1)/N}% [1]
Partial feeder tie	100% or less [2]
No feeder tie	100%

6.3.2. Augmentation Criteria

Distribution high voltage feeder capacity must be augmented or demand management solutions provided if the forecast 50% PoE feeder maximum demand on exceeds the firm ratings as given in Table 3.

[1] "N" represents the number of feeders operating in parallel.

[2] A partial feeder tie refers to a tie with limited back feeding capacity. The firm capacity of a feeder with a partial feeder tie may be set below 100% its thermal capacity.

6.4. Distribution Substations

6.4.1. Rating Standard and Loading Limit

Under normal operation, distribution substation load must not exceed the limit expressed as a percentage of transformer nominal rating as shown in Table 4.

Table 4 Distribution Substation Rating Standard & Loading Limit

Substation Type	Commercial load[3]	Residential load in winter	Residential load in summer
Indoor substation	100%	130%	100%
Kiosk substation	90% [4]	115%	100%
Pad mount substation	100%	130%	100%
Pole mount substation	100%	130%	100%

The loading limits set out in Table 4 apply to existing distribution substations for operational and augmentation purposes. They do not apply to the design of new distribution substations, where capacity is required to meet anticipated load growth.

6.4.2. Augmentation Criteria

Distribution substation capacity must be augmented if the existing or forecast load exceeds the loading limit set out in Table 4 under normal operating conditions.

7. 11 kV Feeder Monitoring/Management Process

An ongoing monitoring process is in place to ensure the electrical network is maintained and operated within the established standards and ratings. The key work practices for monitoring and managing the network at the 11 kV feeder level are:

7.1. Feeder Load Analysis Tables

The Feeder Load Analysis tables provide loading graphs and load analysis as a percentage of the firm capacity rating for each feeder over the last five years. The tables are updated bi-annually to cover both summer and winter loads. Once updated, the tables are published on SharePoint to make them available to Energy Networks.

7.2. Feeder Forecasting

Feeder and zone substation forecasting is a requirement of ActewAGL's Asset Management Strategy. It is carried out once a year and used as an input to the APR (Annual Planning Report), Zone Development Reports and network planning activities.

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[3] Commercial load is assumed summer peaking.

[4] Rating reduced as transformers in kiosks have not been rated and heat tested within the enclosures.

7.3. Annual Planning Report

The Annual Planning Report (APR) provides an annual 'snapshot' of the 132 kV and 11 kV ActewAGL network. It identifies existing or emerging network constraints and proposes solutions to relieve these constraints. The 11 kV feeder information included in the APR is mainly sourced from the Feeder Load Analysis Tables and Feeder Forecasts. The APR is a regulatory requirement, a public document and is published on the ActewAGL external website by 31st December of each year.

7.4. Feeder Load Transfers

Feeders that have been identified as overloaded (i.e. exceeding their Firm Capacity Rating) during the planning process are relieved if feasible, in the first instance, by load transfers to adjacent feeders. Changing the supply to distribution substations from one feeder to another (by moving open points in the 11 kV network through switching) is the most cost effective way to reduce load on an overloaded feeder. Feeder load transfers are initiated by identifying required changes to open points and submitting an ENAA (Electricity Network Alteration Advice) to Network Operations for implementation.

7.5. Feeder Based Projects

If augmentation of an existing feeder or a new feeder is required to relieve constraints or meet new customer load, an options analysis study is done and a business case prepared identifying the preferred option scope, associated costs and timing. If the need is not immediate (ie an emerging constraint), then a Project Justification Report is prepared for inclusion in the next five-yearly Regulatory Submission to the AER.

8. Supply Upgrades – Special Requirements

In circumstances where an interruption of supply could result in unacceptable risk to customers, the standard supply arrangement may not be sufficient. For example a medical facility may require N-2 level of supply security. Consideration should be given to the load type, load size and location. The customer should be advised to evaluate the risks of supply interruption against the cost of providing increased supply security or on-site standby generation.

8.1. On-site Emergency Generation

The need for an emergency backup supply will depend on the security of the primary supply and assessment by the customer of the risk resulting from the interruption of supply.

ActewAGL does not provide on-site emergency backup generation. Customers are responsible for making an assessment whether an on-site emergency generator is required. The on-site emergency supply is to be provided, operated and maintained at the customer's cost.

8.2. LV (400 V) Back up Connection

For a single transformer supply, a low voltage alternative supply should be provided from an adjacent substation as part of the standard supply arrangement if it is technically and economically viable. In general, the provision of a low voltage alternative supply is considered economic, if it increases the cost of supply by no more than 10% of the total project cost. For residential reticulation, additional conditions are specified in the Underground Distribution Standard for inter-transformer and inter-circuit LV ties.

The capacity of the low voltage alternative supply connection depends on a number of factors such as cable and conductor size, voltage drop, capacity and load of the distribution substation from which the supply is provided. Therefore, no guarantee of a backup capacity level can be given to the customer. During an emergency, the customer is required to reduce his load to match the available LV back up supply.

8.3. Special Network Supply Arrangement

Customers should establish whether the standard supply arrangement is adequate. If the standard supply does not meet the customer's needs the supply may be upgraded. Any non-standard supply upgrades are to be funded by the customer.

For particular applications, ActewAGL may recommend upgrade above the standard supply. ActewAGL's recommended supply level should be confirmed in writing with the customer and all records retained for future reference. In the case where the standard supply is not sufficient, but the customer declines to upgrade the supply, the customer should indemnify ActewAGL against future consequences of the decision.

The upgrade may typically include one or more of the following to increase security or reliability of supply:

- Additional transformer capacity,
- More than one transformer for loads above 1000 kVA,
- Additional 11 kV feeder connection,
- Increase in the capacity of the low voltage alternative supply,
- Parallel transformer operation,
- 11 kV flop-over facility,
- Low Voltage (400 V) flop-over facility,
- Remote or automatic operation of switches/breakers,
- Remote load monitoring,
- Dedicated 11 kV feeder, and
- Duplicate 11 kV feeders (parallel feeders).

9. Responsibilities

The Branch Manager Asset Strategy is responsible for the approval of this standard. The Strategic Planning Manager is responsible for review and amendment of this standard as required. All staff involved in distribution network planning and expansion shall comply with this standard.

10. Definitions

50% PoE Forecast Load	Peak load forecast which has a 50% probability of being exceeded in any year (i.e. a mid-range forecast likely to be exceeded once every 2 years), based on normal expected growth rates and one in two year temperature conditions
Credible contingency	A credible contingency is the loss of a single network element, which occurs sufficiently frequently, and has such consequences, as to justify the DNSP to take prudent precautions to mitigate. Commonly referred to an N-1 event
Commercial load	Load of commercial facilities, offices, industrial facility and utility infrastructures
Expected demand	Forecasted or expected summer or winter maximum demand
Feeder tie	Feeder interconnection that has adequate capacity for back feed operation
Firm Capacity	Capacity of supply during single contingency emergency. Usually, the most severe or restrictive faults and outages are considered when assessing firm capacity
Firm rating	An operating rating assigned to a feeder based on the feeder configuration and load type
Major storm	Severe storm affecting more than 10% of customers in the area subjected to storm
Momentary interruptions	Interruptions of short duration during protection operations, auto-reclose, and auto-changeover events, with a typical duration of 2 to 10 seconds
Partial feeder tie	Partial back up refers to ties with limited capacity to back feed
Recommended Supply	Supply arrangement considered to be adequate by ActewAGL after consultation with the customer and consideration of load type, availability of on-site emergency generation, risk of supply interruption and other relevant factors. The level of recommended supply shall be at, or above the standard supply
Residential load	Load of residential customers in either suburban or rural areas
Rural	Areas outside the urban area of the ACT
Thermal capacity	The rating of a network element limited by its thermal characteristics and load pattern
Urban	Area in the ACT occupied by residential suburbs, commercial centres, major industrial districts, education institutions, and transport hubs
CAIDI	**Customer Average Interruption Duration Index** – the ratio of customer interruption durations to the total number of customer interruptions. It is measured in minutes per customer and indicates customer average supply interruption duration
SAIDI	**System Average Interruption Duration Index** – the ratio of customer interruption durations to the total number of customers served. It is measured in minutes p.a. per customer and indicates system average supply interruption duration
SAIFI	**System Average Interruption Frequency Index** – the ratio of total number of customers' interruptions to the total number of customers served. This indicates the average number of interruptions an average customer experiences per annum
Single contingency emergency	A state of the network after single network component outage or network fault