Transmission Planning Criteria Guideline

Application of the Technical Rules Section 2.5

Protected

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1. Context

This Transmission Planning Guidelines document has been prepared by Western Power to aid network planners in the interpretation and application of the Technical Rules in planning work.

Western Power is a regulated network service provider (under the Electricity Networks Access Code 2004 – the Code), providing transmission and distribution network services to the South West Interconnected System (SWIS) of south—west Western Australia. The Technical Rules is a document enabled by the Code in which the performance requirements for the electricity network are defined.

This document intended for use primarily by transmission network planners. It may also be of assistance to other groups within Western Power, such as:

- Distribution Network Planners
- Network Operations
- Engineering & Design
- Asset Performance
- Project Management

This document is intended for application to the Transmission network (66 kV and above). The Distribution Planning Guidelines (DM# 4880519) provides guidance on the interpretation and application of the Technical Rules to the distribution network (≤33 kV).

NOTE: DRAFT ONLY.

THIS DOCUMENT REFERS TO PROPOSED TECHNICAL RULES (SEPTEMBER 2023) THAT INCLUDE CHANGES TO THE TRANSMISSION PLANNING CRITERIA.

THIS DOCUMENT IS EXPECTED TO CHANGE IN COURSE OF THE TECHNICAL RULES REVIEW PROCESS OR POST THE APPROVAL OF THE RULES.

THIS DOCUMENT IS NOT RELEVANT TO THE 2016 VERSION OF THE TECHNICAL RULES.

2. Background

2.1 Electricity Regulation in Western Australia

Western Power is a regulated organisation, with regulation undertaken by the Economic Regulation Authority of Western Australia (the ERA). Western Power is regulated under the Electricity Networks Access Code 2004 (the Code).

2.2 The Technical Rules

The Technical Rules is a document mandated under Chapter 12 of the Code; the scope of the Technical Rules is outlined in Appendix 6 of the Code.

Western Power periodically submits an Access Arrangement (AA) to the ERA for approval and this arrangement applies for a set regulatory period (at present 5 years). The Technical Rules define the required standard of performance the Transmission System must meet.

The Technical Rules is not a static document. Amendment submissions to the ERA can be made by Western Power or the Chair of the Technical Rules Committee at any time and will be processed in accordance with Clauses 12.50 to 12.54 of the Access Code.

The Technical Rules were first applied from 1st July 2007 and include a provision that the existing network and all connected user plant (at 1st July 2007) is deemed to comply with the Technical Rules. This provision ensures that it is not necessary to upgrade parts of the network that are presently operating satisfactorily to new criteria. Any equipment amended or modified since the first implementation of the Technical Rules must comply with the Technical Rules.

Western Power and other network users may apply to obtain an exemption from one or more requirements of the Technical Rules. The process for Western Power to obtain an exemption from one or more requirements of the Rules by applying to the ERA, is described in Clauses 12.40 to 12.49 of the Code. Similarly, the process for a network user to obtain an exemption from one or more of the requirements of the Rules by applying to Western Power is described in Clauses 12.33 to 12.39 of the Code. The exemptions sought by Western Power from the ERA and the exemptions provided by Western Power to customers are published by the ERA periodically on its website.

Western Power is required under the Code to plan, design and operate a network that is compliant to the Technical Rules. Where the Western Power identifies a non-compliance or forecasts the possibility of a non-compliance it will either invest in the network to ensure compliance or seek an exemption. Exemptions are sought where Western Power judges it is economically efficient and prudent not to invest but manage any risks through operations plans.

The Technical Rules are also referred to, and referenced within, the Wholesale Electricity Market (WEM) Rules. Such references are included in the following areas of the WEM Rules:

- Chapter 1 – Requirements for Existing Transmission Connected Generating Systems (Clause 1.40)
- Chapter 2 – Functions and Governance (Clause 2.1), related to AEMO
- Chapter 3 – Power System Security and Reliability (Clause 3.1, 3.2, 3.8)
- Chapter 3A – Requirements for Transmission Connected Generating Systems (Clause 3A.1, 3A.2, 3A.13
- Chapter 4 – Reserve Capacity Rules (Clause 4.5B)
- Appendix 12 – Transmission Connected Generating System Performance Standards (Clause A12.1)

3. Planning philosophy

As a Network Service Provider, it is Western Power's role to provide power transmission and distribution services to generators and load customers within the South-West Interconnected System (SWIS). In providing these services, Western Power not only operates the existing network, but also undertakes planning activities to ensure that new generator connections can be accommodated, and new and growing loads supplied according to established standards.

The Technical Rules define the minimum performance limits that the network must achieve and the assumptions and background conditions under which they must be met. These requirements ensure that the power system can be operated securely and economically.

Network planning often involves assessing the projected performance of the network following the addition of new loads and new generation sources against the Technical Rules. New loads may be in the form of general load growth associated with population and economic growth in established regions, or discrete (often large) loads associated with specific developments. New generation sources may be in the form of new generation to meet load growth requirements, new generation to replace aging generation plant scheduled for retirement or new generation aimed at providing more competitive pricing than existing units.

Where planning studies identify performance deficiencies, solutions need to be developed. Any proposed solution that involves network augmentation will need to meet the requirements of the Access Code – specifically the Regulatory Test (for augmentations above a particular value) and the New Facilities Investment Test (NFIT). These tests are intended to ensure that network augmentations are necessary, economically efficient, and provide a net benefit to the users of the electricity network.

3.1 Power System Performance Criteria

The performance criteria can be separated into different categories, and from these categories, the importance of the criteria in respect to managing the secure operation of the system:

- System Security – of primary importance – an adequate level of security is maintained if specified performance criteria are met. The degree of security assigned to different parts of the network varies based on demand group size and also based on the functional use of the system, such that Perth CBD area loads, and the Main Interconnected Transmission System (MITS) have the highest level of the defined security.
- Reliability – defined and measured through use of evaluation metrics such as Circuit Availability, Loss of Supply Events, and Average Outage Duration, etc
- Quality of supply – also of importance, and likely to become increasing so due to changing system and generating plant characteristics e.g., inverter based plant, which may introduce new quality of supply issues and potentially worsen specific quality of supply metrics e.g., harmonics, voltage fluctuations, etc.
- Specific considerations within these three general performance categories are shown in Table 1.

Table 1: Performance Criteria Categorisation

Type	Criteria	Source of requirement
System Security	System Frequency	TR cl. 2.2.1, WEMR 3B
	Voltage Limits	TR cl. 2.2.2
	Transient Rotor Angle Stability	TR cl. 2.2.8
	Oscillatory Rotor Angle Stability	TR cl. 2.2.9
	Short Term Voltage Stability	TR cl. 2.2.10(A)
	Long Term Voltage Stability	TR cl. 2.2.10(B)
	Temporary Overvoltage	TR cl. 2.2.2.6
	Power Transfer Limits	TR cl. 2.3.6
Reliability	Circuit Availability	Service Standard Benchmarks (SSBs) defined in Access Arrangement (AA5)
	Loss of Supply Events (System Minutes Interrupted)	
	Average Outage Duration	
Quality of Supply	Flicker	TR cl 2.2.4, 2.3.1
	Harmonic content	TR cl. 2.2.5, 2.3.2
	Voltage Unbalance	TR cl. 2.2.6, 2.3.3
	Electromagnetic Interference	TR cl. 2.2.7, 2.3.4

The System Security and Quality of Supply criteria outlined must be met under the system conditions and with the network operating under the relevant planning and operational criteria as defined in Section 2 and Section 5 of the Technical Rules, respectively. Specifically, system performance requirements are outlined in Section 2.2 (Power System Performance Standards) with planning and system security aspects detailed in Section 2.5 (Transmission System Planning Criteria) of the Technical Rules. For the latter, this includes details of the applicable level of security and redundancy that apply to Demand and Generation connections, as well as planning of the wider Main Interconnected System (MITS). Details are also provided over what credible contingency events should be considered for each functional area of the transmission system.

In relation to demand connections, the level of security and redundancy applicable to individual demand connections varies based on the relative size of the demand (specified as a demand group), with further considerations given to substation or customer location e.g., rural, urban, or CBD area. Required security levels range from N-0 and N-1 to N-1-1, with a further N-2 requirement for particular load area (Perth CBD). For areas of the network designed to a N-1-1 security level i.e., a planned outage followed by an unplanned outage, the Planning Criteria must be met at the maintenance period demand, which should be taken as 80% of the group demand unless better data is available. When planning an outage affecting a demand group >250 MVA, generation may be rescheduled in accordance with the WEM Rules to mitigate the impact of any subsequent unplanned or fault outage.

For generation connections, specific requirements are included to limit the loss of generation infeed associated with the connection design arrangement. This requirement acts to place an effective limit on the maximum capacity of generation that can be connected via a single or double circuit or would otherwise be disconnected via a designated credible contingency event[1], in order to minimise the resultant impact on system frequency response.

Load shedding and remedial action schemes (UFLS, UVLS, islanding, pole slip protection) may be used to safeguard the system if it is forced into operation outside the limits of the Technical Rules.

The designated Quality of Supply criteria must be met with the network operating under normal intact system conditions. Western Power does not plan the network to meet the Quality of Supply criteria for outage conditions (either planned or unplanned) due to the relatively short exposure during these conditions.

Long-term planned outages do occur e.g., to completely rebuild a transmission line and Quality of Supply criteria need to be considered in these instances. In these situations, consideration may be given to undertaking some augmentation to aid meeting the Quality of Supply criteria during the planned outage. A cost-benefit assessment should be performed, considering immediate cost, the long term value of any augmentation, and the sensitivity of loads likely to be affected during the outage. If a single customer is particularly sensitive to Quality of Supply issues, it would be advisable to discuss plans and any potential mitigation with them as part of the planning process.

3.2 Credible Load And Generation Patterns

The Technical Rules require that Western Power as Network Service Provider (NSP) operates the transmission and distribution system to achieve the power system performance criteria outlined in Section 0 against all credible load and generation dispatch conditions. This includes those resulting from the Security Constrained Economic Dispatch regime.

The following subsections detail the approach that should be adopted in developing appropriate load and generation dispatch conditions to be used when applying the transmission planning criteria outlined in Section 0.

3.2.1 Load Scenarios

Electricity demand and its patterns are one of the critical factors determining the size, timing and location of demand related and wider MITS investments in network capacity augmentations and other operational and strategic network decisions made by Western Power.

Western Power develops forecast models that can be classified as short-term load (one week), medium-term (up to 10 years) and long-term forecasting (up to 50 years). These forecasts may be segmented by geographical area, load areas, customer type, tariff and different network voltage levels.

The models are also produced at different hierarchy levels, reconciled to ensure consistent results. Not all forecasts are developed for all scenarios, at all levels, or for every year.

Development of Western Power's forecast models is guided by three primary principles: accuracy, transparency, and evidence-based decision-making. The forecasting process checks the validity of forecasts by running statistical tests to ensure consistency at different levels of aggregation.

The accuracy of past forecasts is monitored, and any significant departures analysed for possible causes of inaccuracy. Adjustments are then made in the design of new forecast models, or the type and quality of data used. All input data is assessed for credibility and relevance before being approved for inclusion in the

[1] A credible contingency includes N-2 events where generation is connected via two transmission circuits operating in parallel.

forecasting processes. Western Power measures and aggregates electricity demand averages based on five-minute intervals for the purposes of electricity demand forecasting.

Trends in connected customer count, imported energy from technologies (mainly Distributed PVs) and historical energy demand form the basis of most Western Power energy forecasts. Aside from reconciled and validated actual demand data, other inputs of note in the forecasting methodology are econometric forecasts obtained from reputable sources such as CSIRO and Bloomberg, which are analysed for impact and included where and if relevant.

System peak for the SWIS occurs in summer and most studies relate to summer studies. Most substations experience peak load during summer, a few peak in winter. As a result, some parts of the network may experience higher loads in winter than summer. It is essential that both winter and summer scenarios are considered for these areas. Although for some substations winter loads are higher, summer loads may still be more onerous due to higher thermal stress during summer conditions (plant is rated lower at higher ambient temperatures) and also due to lower power factor loads which cause greater voltage stress on the network (winter loads tend to be heating related and are more resistive).

Due to variability, forecasts are expressed at three Probability of Exceedance (PoE) levels, rather than as single point forecasts. For any given season or year, PoE10, PoE50 and PoE90 are defined as:

- PoE10 or 10 per cent PoE that demand value is expected to be exceeded, on average, one year in 10.
- PoE50 or 50 per cent PoE that demand value is expected to be exceeded, on average, five years in 10.
- PoE90 or 90 per cent PoE that demand value is expected to be exceeded, on average, nine years in 10.

In terms of application, when performing studies to assess the requirements of demand connections or potential wider MITS reinforcement and augmentation requirements, the starting point is typically the developed load forecast for each supply point substation (or major customer):

- System minimum and system peak demand conditions, being based on PoE50% minimum and PoE10% maximum demand forecasts
- Substation non-coincidental peak demand conditions, being based on PoE50% minimum and PoE10% maximum demand forecasts.

The system peak load forecast (applied to each substation/supply point) is for use in studies relating to system performance. The substation peak load forecast is for use in assessing substation capacity. When studying performance for distinct parts of the SWIS, it may be necessary to develop an ‘area’ peak load forecast.

Load forecasts include information relating to the ‘raw’ power factor of the load i.e., the load power factor, prior to compensation at the substation busbar by capacitor banks. Capacitor banks and the reactive component of loads are to be modelled separately. The separation of load and reactive compensation in modelling is an integral component to the reactive reserve study methodology used by Western Power in assessing long term voltage stability of the network.

Further details of Western Power’s energy and customer forecast methodology are provided in the published document Attachment 7.6 on the ERAWA website[2].

[2] www.erawa.com.au/cproot/22445/2/AAI---Attachment-7.6---Energy-and-Customer-Forecast-Methodology.pdf

3.2.2 Generation Patterns

In relation to generation scheduling and dispatch there are two main considerations that apply to modelling of the SWIS and assessing network compliance against the Planning Criteria within the Technical Rules :

- The development of an appropriate generation dispatch (to accompany the demand scenarios), and
- Considerations associated with constrained access regime used in the Wholesale Electricity Market (WEM).

Generation dispatch scenarios

The development of an appropriate generation dispatch to accompany the demand scenarios outlined in Section 3.2.1, that is projected SWIS system peak and minimum demand, and substation co-incidental peak based on 50% PoE and 10% PoE forecasts. For each of these demand scenarios several generation dispatch scenarios are expected to be developed.

The different generation dispatch scenarios are developed to be used for particular planning studies involving, generation connections, demand connections and wider MITS planning. These are based on credible but deliberately varying generation dispatch profiles, and typically include: merit order based dispatch; high north renewable dispatch; and high southern (conventional) dispatch profiles, and associated derivatives of each, largely to reflect historical dispatch regime characteristics and expected potential developments in future years.

The development of these distinct dispatch scenarios considerations should include:

- scheduling sufficient generation to match the respective demand scenario forecast,
- providing sufficient spinning reserve requirements to cover contingency outages
- considering planned generation plant retirements plus the timing of new generation development projects
- and the coincidence or dependability of generation output and assumed availability at the respective demand condition.
- Appropriate consideration of energy storage characteristics. In conjunction with AEMO, 4 hour storage agreed as included at 100% of capacity, for 2 hour storage 50% of capacity. For the peak system case storage is considered as a generator (and as a load at minimum demand).

Sensitivity studies should also be conducted to ensure that generation dispatched out of merit order e.g., as a result of extended maintenance, forced outage or fuel restrictions does not advance triggers for augmentation.

Constrained access regime

The second aspect for consideration with respect to generation scheduling and dispatch are the revisions to the Wholesale Electricity Market (WEM) which introduced a constrained access regime. A key element of this is a new Security Constrained Economic Dispatch (SCED) regime which from Oct 2023, will actively seek to dispatch generation in the most economic manner to deal with existing and emerging network constraint issues and manage the resulting constraint costs to yield the optimum dispatch for each interval.

The SCED regime is a significant change from the historical approach which allowed network access for generators on the basis of connection application and connection date, essentially allowing historic generation plant network access over more recently connected facilities. Such historical network access resulted in a much more predicable generation dispatch schedule, being predominantly merit order based within the existing generation facility access rights, which in turn allowed a number of discrete generation dispatch scenarios to be developed for use in transmission network planning studies e.g., merit order dispatch, high north, high south dispatch etc.

As noted above, in order to ensure consistency in application for assessment of generation connections and demand connections, the development of discrete generation dispatch scenarios is still a useful starting point for such assessments. However, there is also a need to consider the outcomes and implications of the SCED process and hence development of a representative SCED profile for SWIS system peak demand (on an annual basis) is also considered necessary. This can be used as an accompany generation dispatch profile in the assessment of localised generation and connection planning to ensure that some element of the wider SCED philosophy is captured, whilst at the same time not over weighting the connection planning outcomes on the basis of relatively short term visibility of potential network constraint and curtailment issues. This will also avoid over burdening individual connection participants with the costs associated with deep system reinforcement.

In relation to planning of the wider MITS, greater emphasis and consideration of the SCED approach should be routinely applied as:

- the prospective network reinforcement and augmentations have potentially high capex requirements e.g., adding new 330 kV overhead lines,
- the power flows on the wider MITS are influenced by the actual generation dispatch to a much greater extent than the localised connection assets connecting demand and generation customers.

As such, whilst it is expected that the developed static generation dispatch and demand schedules used in the localised demand and generation connection planning e.g., high north, merit order for system peak and minimum demand, etc will also be used for planning of the MITS, there will also be greater direction consideration and application of SCED outcomes. This will include actively running and applying the developed SCED tool and methodology to fully identify and quantify the impacts of potential capacity shortfalls on the wider MITS that leads to curtailment of generation and associated market costs, but also directly considering the costs of a revised generation dispatch and potential cost savings of proposed reinforcement and augmentation options. Additionally, for planning of the MITS, solution options may actively include both traditional network reinforcement and augmentation schemes e.g., capital investments in new substation or transmission network capacity, as well as market based solution costs where this can be shown to be more cost effective.

4. Transmission System Planning

4.1 Background

Section 2.5 of the Technical Rules sets out the transmission system planning criteria applicable to the SWIS. The Planning Criteria has specific requirements to be followed by Western Power (as Network Service Provider) when planning demand connections, generation connection as well as the wider sub-transmission system and Main Interconnected Transmission System (MITS). This includes detailing the levels of network security or redundancy that should be considered for each specific area of the transmission system as well as the applicable pre- and post-system conditions that the system should be considered when evaluating compliance for credible contingency events. These are specified individually throughout the Planning Criteria and as a considered to apply to each area of the transmission system.

It should be noted that the Planning Criteria set out in Section 2.5 of the Technical Rules represent the minimum requirements for planning and operation of each area of the transmission system in most situations.

The section is structured as follows:

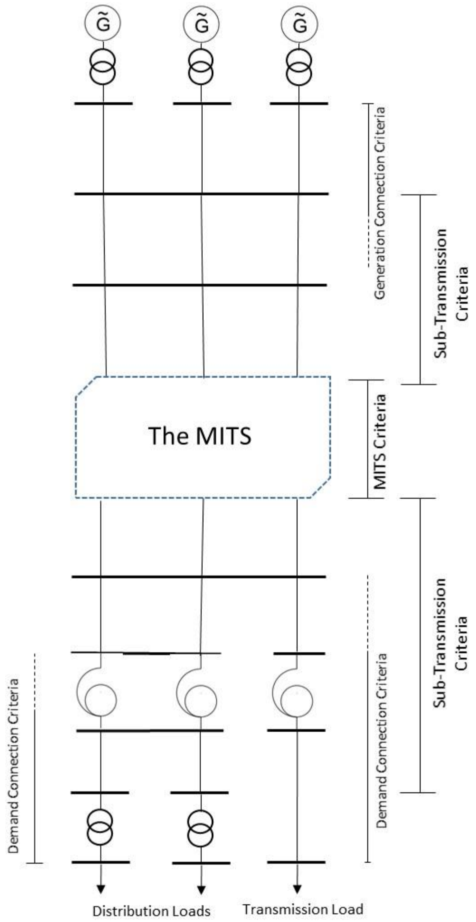
- An overview is provided in Section 4.1 of the structure of transmission planning criteria, including details of some of the key elements and aspects detailed under the respective network area.
- For each of the three main planning criteria areas e.g., demand connection, generation connection and MITS planning, a summary is provided (in Sections 4.3 to 4.5) of the key characteristics, considerations and aspects that are relevant for network planning. This includes detailing the particular credible contingency events that apply for each area of the transmission system, as well as providing reference and highlight of other areas of the relevant planning criteria that may be relevant for network planning application.
- As part of the revised planning criteria, economic guidance is provided as to aspects that should be considered when applying the planning criteria and in particular when planning or designing elements of the transmission system to a standard that deviates from the specific requirements outlined. This is presented in Section 4.6
- In addition to the network planning application of the revised planning criteria it is also important to consider operational aspects related to planning and managing transmission plant outages as well as other aspects relevant when securing the transmission system to manage or deal with the consequences of unplanned or fault outages. Details of the relevant considerations are presented in Section 4.7
- To support understanding of the application of the Transmission Planning Criteria a number of application examples are presented in Section 4.8 which cover a number of specific areas within the Planning Criteria. These examples have been chosen to provide a wider range of application examples including demand connection, generation connection and wider transmission planning examples.

4.2 Overview of Planning Criteria

The previous transmission planning criteria that applied to the SWIS was structured around geographic network areas e.g., metropolitan, country, CBD etc with stipulated network security and redundancy requirements then based on operating voltage or substation design. This approach presents potential inconsistencies in relation to network security level experienced by end customers, including between those located in urban and rural network areas. It lacks clear trigger thresholds for increasing the security and reliability of network to cater for increasing substation demand. Also, the previous version of the

Technical Rules did not give explicit consideration to the security level that should be afforded to generation connections or other associated risks to wider system security that may be posed by increasingly larger capacity generation connections such as now being experienced.

To address the range of identified issues and to bring the transmission planning criteria in the Technical Rules more in line with the planning criteria in other international jurisdictions, a new structure has been adopted for the latest version of Technical Rules. This explicitly states the transmission planning criteria and requirements for three distinct parts of the SWIS. These are:



- Generation connections – detailing the specific aspects that should be considered when planning and designing generation connections. This includes explicit consideration of the maximum allowable loss of generation infeed capacity that is permitted in order to avoid undue disturbance on the wider transmission system.
- Demand connections – this section sets out a new structure for the design and planning of demand connections based on a demand group structure, with the required connection security and design reliability increasing as the group demand increases.
- MITS and sub-transmission planning – whilst the design of generation and demand connections covers a significant proportion of the development of the transmission system there are also elements of the system that are used by more than one demand (or generation) connection or perform other relevant functions, including transportation of large power flows from one part of the transmission system to another. As such there is also a need to set out the requirements for this wider part of the transmission system, termed the Main Interconnected Transmission System (MITS). The criteria for the MITS is also applied to the sub-transmission system, which forms the interface between the MITS, demand and generation. As outlined in Section 4.5 of this Guideline, there is one additional requirement for MITS compared to sub-transmission related to the occurrence of a single circuit breaker failure resulting from a single phase to earth fault (clause 2.5.5.3(b) of the Technical Rules).

An overview of the structure of the above elements of the transmission system is presented in Section 2.5.2 of the Technical Rules with the specific technical requirements for each of the above areas set out in Sections 2.5.3, 2.5.4 and 2.5.5.

A summary of the key relevant considerations with respect to network planning are presented in the following subsections (Section 4.3 to 4.5), with each stating:

1. Applicable pre- and post-fault background system conditions for the assessment.
2. Considered credible contingency events, including specifying the specific types of plant and equipment faults and planned outages that should be considered.
3. Allowable limits in relation to permitted loss of demand or generation infeed capacity.
4. The applicable response and restoration timescales that apply (for demand connection).

The intention of the following subsections is not to provide a wholesale repetition of the Transmission Planning criteria, principal focus will be made to the above aspects when detailing specific network planning considerations that should be examined when planning the respective parts of the SWIS.

4.3 Generation Connection Criteria

Section 2.5.3 of the Technical Rules presents the technical requirements in relation to the planning and design of generation connections. Unlike the previous iterations of the Technical Rules this section sets out specific allowable limits in relation to the permitted loss of power infeed that can be interrupted or disconnected due to a fault or planned outage. Section 2.5.3.1 of the Technical Rules provided the requirements for limits to power infeed loss risk, and several key points relevant for planning generation connections including:

- The various considered plant and equipment fault and planned outages (considered as credible) are stated throughout the section.
- The maximum permitted loss of power infeed (generation supply) capacity is covered by the "infeed loss risk limit", which is 400 MW. A smaller limit value of 150 MW is also stated for planned outages of substation busbars.
- When calculating the loss of power infeed resulting from credible contingencies there are a number of individual elements relevant to the calculation, including total capacity of generation that would be disconnected by a contingency event, as well as the consideration of any demand or import from external system that would be interrupted by the same contingency event. Details are provided in Section 2.5.3.1(a) of the Technical Rules.

In relation to the generation infeed loss risk limits, the noted limit is 400 MW. This covers historical single generator contingency limits e.g., Collie Power Station (circa 350 MW), and is also considered the maximum value that should be adopted in most cases, unless further detailed evaluation and consequent discussion with AEMO indicates that the risk can be appropriately managed.

A generation infeed loss limit greater than 400 MW could be appropriate when evaluation of the likelihood of the total generation dispatch occurring that could be affected by a single contingency event indicates that this is expected to occur relatively infrequently e.g., < 50 hours per annum. For such circumstances, AEMO will need to constrain or curtail the potential total generation dispatch as part of the SCED operation so that the higher infeed loss risk value will not occur in practice (to manage power system risk).

In considering an alternative generation infeed loss limit, factors such as spinning reserve availability, the potential market cost impacts of procuring additional spinning reserve, and comparative capital cost savings need to be considered.

The potential system frequency impacts, will vary based on total system demand, connected generation plant capacity and inertia, and level of spinning reserve available. As such, any alternative generation infeed loss limit would need to be agreed with AEMO.

Additionally, when planning the connection of new or revised generation plant power system analysis and capacity evaluation studies should consider:

- real and reactive power output settings for the generator in question,
- set-up of the wider SWIS DIgSILENT network analysis model e.g., wider generation dispatch assumptions that should be adopted and alternative demand scenarios that should be considered.

stipulated requirements in relation to plant and equipment thermal loadings, acceptable system voltage conditions and system stability[3].

Under the above circumstances there may be reasonable technical and economic justification to deviate from the stated infeed loss risk limit if the risk can be appropriately managed.

4.4 Demand Connection Criteria

Section 2.5.4 of Technical Rules presents the technical requirements in relation to the planning and design of demand connections. Central to application of the new demand connection criteria is the concept of a demand group. This is a specific total value of demand (based on peak demand) for a site or group of sites that collectively take power from the transmission system. Examples of demand groups may include:

- Individual zone or terminal substations, or specific assets within a substation depending on network operation and isolation points within the substation e.g., a demand group could apply to a whole zone substation, with a sub-demand group applying to an individual zone substation transformer.
- Transmission circuits supplying one or more zone or terminal substations, where the group demand could, depending on the nominal direction of power flow to end substation loads, be the summation of the downstream substation loads.
- Sites with a mix of generation and demand connections or an energy storage facility. In this case, the security afforded to the demand connection elements or storage system when operating as a load should not be less than would otherwise apply to a typical demand connection at another location.

The use of the demand group structure in the latest version of the Technical Rules for demand connections re-focuses the network security and design requirements explicitly in relation to substation demand. This differs to the previous version of the Technical Rules where planning requirements were dictated by network location, voltage or other aspects as was the case in the 2016 version of the Technical Rules and the versions prior to it.

In a similar manner to the structure of the generation connection requirements discussed in the previous sub-section, there are a number of key points relevant for planning demand connections:

- The various plant and equipment faults and planned outages are defined in Technical Rules clause 2.5.4. Clause 2.5.4.4 defines acceptable credible contingency fault outages starting with an intact transmission system, and clause 2.5.4.6 defines acceptable credible contingency fault outages starting with a local system planned outage. There are also specific requirements for planning the transmission system capacity for demand groups covering the Perth CBD area.
- The transmission system background conditions applicable to demand connections are stated. These include treatment of maintenance period demand, transfer capacity between demand groups, the acceptability of rescheduling generation in accordance with WEM Rules during planned outages, plus requirements related to plant and equipment thermal loadings, acceptable system voltage and system stability conditions.
- Following the occurrence of a credible contingency involving a fault outage (whether starting from an intact system or with a prior planned outage) the level of network security and restoration requirements are structured based on demand group size and network location. Higher capacity demand groups have greater network security requirements to meet system load rejection limits and

[3] There are specific definitions for the terms: unacceptable overloading; unacceptable voltage conditions; and system instability, in the Glossary of the Technical Rules and these refer back in some cases to the Power System Performance Standard in Section 2.2 of the Technical Rules.

manage potential value of unserved energy. The specific restoration requirements for a particular demand group are shown in Table 2-10 of the latest version of the Technical Rules.

- When reviewing the supply restoration requirements set out Table 2-10 there are a number of applicable table notes. These notes relate to supply restoration and need to be read in conjunction with the stipulated requirements. Notes have been included to provide some acceptable timeframes under which restoration actions, particular remote switching, should be completed whilst recognising the design standards that apply to typical Western Power zone and terminal substations.

Changes compared with the previous planning criteria

The revised transmission planning criteria has been developed with the central theme of grouping and standardising network security and reliability design aspects based on increasingly levels of connected demand. However, in many areas of the transmission system, the revised requirements are not significantly different from the previous transmission planning criteria (refer to Technical Rules from 2016).

Table 2, below, compares demand groups in the new planning criteria with the previous criteria from 2016. Most of the demand groups map to existing planning criteria with no changes to the security requirements.

(Refer to table in the next page)

Table 2: Copy of Table 2-10 from the Technical Rules with previous criteria mapping

Area	Loss of demand	Considered *credible contingency*	Mapping to current Technical Rules
Rural	<10 MVA	*zone substation transformer*	Same as N-0 criteria in clauses 2.5.2.1(a) and (b)
	≥10 MVA & <60 MVA	*zone substation transformer*	Same as N-1 criteria 2.5.2.2(d) for N-1 substations.
	<20 MVA	*transmission circuit*	Same as N-0 criteria in clauses 2.5.2.1(a) and (b)
	≥20 MVA & <90 MVA	*transmission circuit, generator circuit* or *reactive equipment*	Slightly lower standard than N-1 criteria in clause 2.5.2.2
	≥90 MVA & <250 MVA	*transmission circuit*, *generator circuit*, *reactive equipment* or *busbar*	Same as existing N-1 criteria in clause 2.5.2.2 except that a busbar outage is considered a credible contingency event.
Urban	<60 MVA	*zone substation transformer*	Same as N-1 criteria in clause 2.5.2.2(d) for N-1 substations. Increase in security standard for NCR and 1% risk substations. [4]
	<90 MVA	*transmission circuit*, *generator circuit* or *reactive equipment*	Same as N-1 criteria in clause 2.5.2.2.
	≥90 MVA & <250 MVA	*transmission circuit*, *generator circuit*, *reactive equipment* or *busbar*	Same as existing N-1 criteria in clause 2.5.2.2 except that a busbar outage is considered a credible contingency event.
Perth CBD	<60 MVA	*zone substation transformer*	Same as clause 2.5.3(b).
	<90 MVA	*transmission circuit*, *generator circuit* or *reactive equipment*	Same as clause 2.5.3(b).
	≥90 MVA & <250 MVA	*transmission circuit*, *generator circuit*, *reactive equipment* or *busbar*	Same as clause 2.5.3(b) except that a busbar outage is considered a credible contingency event.
All areas	≥250 MVA	*transmission circuit*, *generator circuit*, *reactive equipment* or *busbar*	Similar to clause 2.5.2.3 except that the threshold is now based on demand.

[4] Although noted as an increase in security of NCR and 1% risk substations, given that in many cases the existing NCR requirements cannot be implemented in practice e.g., use of RRST, such substations are already supposed to be operated to N-1 standard. Hence, in such cases the proposed approach simply re-codifies the requirement that effectively exists currently, and as such does not lead to an increase in security design requirements.

For some demand groups, the new transmission planning criteria appropriately updates the requirements. The following outlines those changes.

- For NCR and 1% risks criterion substations, when taken alone, the new demand groups represent an increase in security. Achieving the NCR criterion for existing substations using RRSTs is challenging. Western Power has historically relied on the NCR criteria and the 1% risk criterion to manage capital restrictions and so these mechanisms represent a misalignment in the security and reliability of the network. As a result, some substations in rural areas of the network with lower demand are afforded a higher reliability standard than urban areas that have higher loads. Under the proposed transmission planning criteria, this misalignment would be corrected for new substations. For existing substations, the flexibility introduced through economic assessment provisions that allow for higher or lower standards to be planned for where economic, enable the existing substations to remain compliant whilst providing an opportunity for strategic investments where this is prudent.
- Busbar outages have not been explicitly covered in the planning criteria previously, except under the N-1-1 criteria. The inclusion of busbar outages covers a gap in the existing rules. In practice, the inclusion of busbar outages should not have a significant impact:
  - The rural demand groups in the ≥90 MVA & <250 MVA range should already be able to manage such a fault outage via remote switching, although there may be a need to temporarily loose up to 60 MVA of load, which is consistent with the proposed requirements (refer to the footnotes to the demand group table in the proposed Technical Rules).
  - The urban demand groups in the ≥90 MVA & <250 MVA range are likely to be terminal stations, which within the Perth Metro area should already be able to manage such a fault outage via remote switching. Like the proposed treatment for rural demand groups, there may be a need to temporarily loose up to 90 MVA of load[5]. However, this is consistent with the proposed requirements (refer to the footnotes on the demand group table in the proposed Technical Rules).

    Western Power has identified one substation where the footnote on the demand group table would apply. For Mason Road substation, given the number customer connections and the size of those connections, it would be appropriate to consider a fully compliant (i.e., N-1-1) configuration and this would represent an upgrade.
  - For the Perth CBD, demand groups in the ≥90 MVA & <250 MVA range are only likely to occur on the 132 kV double circuit lines supplying Hay Street or Milligan Street in the case where there is a total loss of supply capacity (N-2 failure) within the other substation e.g., the combined Hay Street and Milligan Street load is supplied on the 132 kV circuits supplying Hay Street (for a loss of infeed at Milligan Street or vice-versa). In this case further fault outages, beyond the occurrence of a N-2 fault that led to the combined Hay St / Milligan St load to supplied via one set of infeeding 132 kV cables, are not considered credible. Hence, a demand group in this range is unlikely to occur in practice within the Perth CBD[6] under intact conditions.
- For the All Areas demand group, the N-1-1 criteria is effectively captured based on demand thresholds rather than an explicit sub-network. The changed approach introduces flexibly as the system needs change. The following areas represent a step-change in the requirement:

[5] Should the load increase within demand group such it exceeds 90MVA and therefore the requirement to be secure for a busbar outage becomes applicable it would typically require for the busbar in question to be sectionalised (e.g., install a bus section circuit breaker).

[6] Note that East Perth Terminal substation does not fall within the designed CBD boundary as it is located north-eastwards of the defined CBD boundary of Wellington Street and Hill Street.

- The 132 kV terminal stations in Perth metropolitan area are already part of the existing N-1-1 criteria requirements. However, it is noted that some existing terminal stations were designed prior to current planning practices and the introduction of the Technical Rules[7].
- Large demand groups (>250 MVA but less than 400 MVA) supplied from existing 132 kV zone substations and from terminal substations outside of the Perth Metro area. This change is appropriate and required for future developments. The updated standards are critical to support the scale of future developments expected on the power system.

For these areas where the existing configuration does not align with the proposed requirements, the flexibility introduced through economic assessment provisions that allow for higher or lower standards to be planned for where economic, enabling the network to remain compliant (including where grandfathering provision remain) whilst providing an opportunity for strategic investments where this is prudent. As such, the increased standards are not expected to result in an immediate step-change in capital investment unless this is critically necessary.

4.5 MITS and Sub-transmission Planning Criteria

The Main Interconnected Transmission System are the parts of the transmission system that are detailed in Technical Rules clause 2.5.2.(b), and includes:

1. all 330 kV terminal stations and transmission circuits connected to the 330 kV network by three or more 330 kV circuits;
2. all terminal stations providing direct connection to generation in excess of 600 MW; and
3. the transmission circuits connecting terminal stations point 2) above to the transmission elements specified in point 1) above.

The sub-transmission system means any part of the transmission system that is not part of the MITS.

In terms of the planning of the MITS and the sub-transmission system, the network security and design requirements presented are similar to those already presented for the demand connection criteria. The main difference relates to the background system conditions under which the MITS should be planned, and network security and reliability is assessed against.

As noted in Section 3.2.2 of this Guideline, there are likely to be a number of potential generation dispatch and system demand scenarios that will be used by Western Power when planning the MITS and sub-transmission system. These will vary in detail in future years based on outturn and forecast generation development projects and demand projections but are broadly considered to be variations of the following two typical scenario concepts: System Security scenario, and System Economy scenarios.

The System Security and System Economy scenarios, and derivatives, represent a range of disparate demand and generation dispatch scenarios. The approach is intended to ensure that the overall power system is planned and operated securely against the variety of credible scenarios. The specific details of these scenarios, including the overview of typical assumptions to be adopted are detailed in the following subsections.

At the end of the section, a key difference between the MITS and sub-transmission system planning requirements is highlighted. Clause 2.5.5.3(b) of the Technical Rules applies only to the MITS and relates to the occurrence of a single circuit breaker failure resulting from a single phase to earth fault.

[7] Neerabup, Guilford and Northern Terminals are examples.

4.5.1 System Security Background

The intent of the System Security Background is to allow the planning of the transmission system to consider a range of credible but challenging future system conditions to ensure that there is sufficient transmission capacity to meet demand reliably and securely across a range of disparate outcomes.

The System Security Background represents the planning assumptions typically used when applying the planning criteria, such as a worst case demand forecast and with SCED. This is then modified to represent a credible worst case dispatch scenario for the area of the network being investigated. Western Power, as Network Service Provider, must meet the planning criteria set out in Technical Rules Clause 2.5 under this background condition and must invest in transfer capacity to facilitate compliance.

The System Security Background conditions planned for should include, as a minimum, system peak and minimum demand scenarios. Given the different system limitations expected to occur in system peak and minimum demand periods, the range of credible conditions and assumptions should vary and should be developed and studied by Western Power.

The System Security Background conditions are used in the development of Western Power's Transmission Systems Plan and typically used for connection studies.

System Peak Demand

- System peak demand corresponding to 10% PoE forecast
- A credible generation dispatch case for system peak demand conditions based on SCED principles and developed in conjunction with AEMO – see Section 3.2 of this Guideline.
- Static reactive compensation plant at transmission voltages and zone substations set to maintain voltages within the normal operating range and ensure maximum reserves are maintained on dynamic reactive compensation and generation.
- Industrial and embedded generation outputs set to historic typical values at times of system peak demand to ensure typical net demand transfer.
- Transmission network status and anticipated developments, including appropriate network open points, remedial action schemes e.g., customer intertrips, run-back schemes etc, committed customer and network reinforcement projects.
- Energy storage operating as either a load or a generator depending on the worst case operating condition (typically, at 100% or 50% of capacity depending on storage duration – see section 3.2.2 of this Guideline).

System Minimum Demand

- System minimum demand corresponding to the 90% PoE forecast
- A credible generation dispatch case for system minimum demand conditions based on SCED principles and developed in conjunction with AEMO – see Section 3.2 of this Guideline. This should also consider the status and prospective output for distribution and residential customer connected PV, where this may impact materially on the resultant minimum demand value.
- Static reactive compensation plant at transmission voltages and zone substations set to maintain voltages within the normal operating range and ensure maximum reserves are maintained on dynamic reactive compensation and generation.
- Industrial and embedded generation outputs set to historic typical values at times of system minimum demand to ensure typical net demand transfer.

- Energy storage operating as either a load or a generator depending on the worst case operating condition (typically, at 100% or 50% of capacity depending on storage duration – see section 3.2.2 of this Guideline).

4.5.2 System Economy Background

The intent of the System Economy Background is to ensure that there is an efficient level of transmission capacity to meet demand reliability and securely at typical system peak and minimum demand conditions, whilst minimising the impact of constraints on the WEM.

The System Economy Background is intended to represent the most likely network assumptions and the lowest cost, highly renewable dispatch ignoring any network transfer constraints. This approach is used to identify boundaries that have the potential to lower overall system cost through augmentation.

Under the System Economy Background condition, all boundaries identified as constraining the most efficient dispatch outcome must be investigated and monitored to ensure the most efficient outcome between market constraint cost and network transfer capacity augmentation. Where there is sufficient economic justification then the Network Service Provider must seek to augment the network transfer capacity.

At a high level, specific consideration is expected to be include of the following areas:

System Peak Demand

- System peak demand corresponding to 50% PoE forecast
- A credible generation dispatch case for system peak demand conditions based on an unconstrained transmission network and developed in conjunction with AEMO – see Section 3.2 of this Guideline.
- Static reactive compensation plant at transmission voltages and zone substations set to maintain voltages within the normal operating range and ensure maximum reserves are maintained on dynamic reactive compensation and generation.
- Industrial and embedded generation outputs set to historic typical values at times of system peak demand to ensure typical net demand transfer.
- Energy storage operating as either a load or a generator depending on the typical operating condition relevant for the demand being considered, which may be zero output.

System Minimum Demand

- System minimum demand corresponding to 50% PoE forecast
- A credible generation dispatch case for system minimum demand conditions based on an unconstrained transmission network and developed in conjunction with AEMO – see Section 3.2 of this Guideline.
- Static reactive compensation plant at transmission voltages and zone substations set to maintain voltages within the normal operating range and ensure maximum reserves are maintained on dynamic reactive compensation and generation.
- Industrial and embedded generation outputs should be set to historic typical values at times of system minimum demand to ensure typical net demand transfer.
- Energy storage operating as either a load or a generator depending on the typical operating condition relevant for the demand being considered, which may be zero output.

Relaxation on economic grounds

The transmission planning criteria for the MITs allows for the potential relaxation in relation to system investments and augmentations identified through the System Economy scenario. Where potential network investments to secure generation capacity and system demand across the MITS are identified these are only required to be implemented where there is sufficient economic justification.

If a potential network reinforcement or augmentation was identified through the System Economy scenario and the potential capital costs of the remediation scheme and investment action are excessive relative to the potential benefits that may be gained, then the scheme may not be economically justified.

Reference should be made to Section 4.6 of this Guideline for clarity on the required assessments to be performed. Note that any economic assumptions made as part of this economic assessment should align with the Whole of System Plan published in accordance with the WEM Rules.

4.5.3 Difference between MITS and sub-transmission planning criteria

The MITS planning criteria also includes a specific requirement under clause 2.5.5.3(b) that does not apply to the sub-transmission system. This relates to the occurrence of a single circuit breaker failure resulting from a single phase to earth fault. If the fault occurs at times system demand < 80% of expected transmission system peak load there should be no unacceptable overloading of transmission equipment. Under clause 2.5.5.3(a) there should be no loss of demand capacity for other types of transmission equipment fault outages. This is essentially the same criterion outlined in 2.5.2.4 Circuit Breaker Failure in the previous version of the Technical Rules.

4.5.4 Specific fault and plant outages

Section 2.5.5 of the Technical Rules sets out the specific fault and plant outages that are considered as credible contingencies as well as the post-fault system performance criteria that should be applied for MITS planning. This includes permitted loss of demand for certain contingency events in line with the requirements shown in Table 2-10 of the Technical Rules under clause 2.5.4.

4.6 Economic Guidance

This section provides guidance on the economic considerations and justification needed for investments in transmission infrastructure when designed to a higher or lower standard than outlined in the transmission system planning criteria in Section 2.5 of the Technical Rules.

This guidance is not intended to replace or override requirements in the Access Code or other higher order regulatory instruments, such as the *Electricity Industry Act 2004* or the WEM Rules.

When determining the costs and benefits of any proposed deviation from the applicable transmission system planning criteria, Western Power should consider, where applicable:

- Calculating the capital, operating and whole-life costs of a design that is compliant with the Technical Rules to act as a benchmark for comparison against the alternative design.
- Valuing the potential reliability impacts of the alternative design. This is expected to include consideration of effects on:
  - Western Power's performance metrics and SSB targets e.g., Loss of Supply Event Frequency (LoSEF) and Average Outage Duration (AOD); and
  - other metrics for valuing effects on, or for, end Users and customers e.g., value of customer reliability or lost load.

- Valuing the potential impacts of the alternative design on operational activities and outage management plans. Considerations could include, but are not limited to, effects on:
  - incremental network losses;
  - Essential System Services (ESS) – for example, where the alternative design affects the market cost of generation or load rejection;
  - reactive power requirements, including generation loading, if applicable;
  - the WEM including system constraint management, and potential re-dispatch of generation to alleviate system constraints if contingencies occur; and
  - operational risk mitigation – for example, the use of temporary generation to maintain operational capabilities.
  - deliverability of the works program.
- Performing whole-life and net present value costing calculations for the alternative design taking account of:
  - capital and operating costs of the alternative design, or if the alternative design is to defer or negate investment, calculating the expected additional operational costs associated with the existing infrastructure;
  - power system operational costs – for example, the effects of network losses, ESS, reactive power requirements, the WEM and operational risk mitigation;
  - costs of any constraint management or re-dispatch of generation;
  - typical annual system loading;

    Note: Typical annual system loading may be considered using system load duration curves to develop equivalent annualised values for the above cost values.
  - sensitivities of the above, where applicable, to evaluate how the identified costs may change through credible ranges of values.
  - cost of undertaking outages between alternative designs.
- Documenting other factors that may be affected by the alternative design, such as:
  - impacts on other generation or any connection queue;
  - precedent for future connection designs; and
  - any other benefits the alternative design may provide.

    Note: For one or more of the above aspects, it may be necessary to evaluate the potential impacts of the alternative design option using a qualitative evaluation scale as direct quantitative calculation for direct financial impacts may not be possible.

When determining whether to proceed with any proposed deviation from the applicable transmission system planning criteria, Western Power should typically:

- Undertake a multiple criteria evaluation that considers whether the whole-life cost for the alternative design is comparable to the benchmark compliant design option, or whether it is significantly higher or lower (based on the guidance above).
- If the quantitative analysis indicates there is a significant and identifiable cost saving through the alternative design, then reference should be made to supporting qualitative evaluation to identify if any of these are considered sufficiently critical to outweigh the potential cost savings.

- If the quantitative analysis indicates the alternative design is broadly comparable with the compliant design or the costs are higher, then unless the qualitative evaluation suggests there are significant non-quantified benefits that can be obtained, then the compliant design should be progressed.

4.7 Operational Considerations

Decisions made by planners considering planning timescale significantly affect the network access for equipment maintenance in operational timescales, when operators are required to ensuring system security and network operability is maintained.

In planning timescales, network access for maintenance purposes is **primarily** provided for through the application of N-1-1 planning criteria. The N-1-1 is intended to ensure there is sufficient network capacity to allow for outages on the key parts of the network where alternative approaches to achieving outages would not be appropriate.

Relaxations to the planning criteria are provided for in operational timescales. The relaxations are provided only to the extent that there is no unacceptable overloading of equipment or unacceptable voltage conditions.

In applying the transmission planning criteria, the potential relaxations permitted in operational timescales and their limitations should be considered. The relaxations in operational timescales are as follows:

- In relation to voltage, these limits are outlined in Sections 2.2.2.2 to 2.2.2.5 of the Technical Rules. For N-1-1 contingencies, the expectation is that the tighter voltage limits will be used in planning timescales and will lead to improved voltage security in operational timescales when less onerous limits apply for the same system conditions.
- In relation to primary equipment overloads, in planning timeframes, pre-determined static equipment ratings are used based on worst case seasonal operating conditions. In operational timescales, there is an opportunity to utilise more relaxed ratings based on real time conditions, such as dynamic and short time overload ratings. The expectation is that the additional network thermal capacity may lead to more secure operational outcomes for N-1-1 contingencies than would otherwise be the case compared to planning timescales.
- The N-1-1 planning criteria is also reliant on SCED to ensure a secure power system during planned outages, which is a requirement for outage approval. However, where SCED outcomes require significant market generation to be constrained off or the constrain on of costly market generation to facilitate network outages, the cost impost to the WEM may restrict network access and prevent vital maintenance from being undertaken. Such scenarios are expected to be identified in the Planning timescale through the application of the System Security and System Economy background conditions in Planning studies and resolved through network investment accordingly.
- The N-1-1 planning criteria also makes use of network reconfiguration (see note under clause 2.5.5.5(a)) to achieve N-1-1 compliance. In general, this is to be avoided where possible for reconfigurations involves network radialisation, particularly where this will result in load shed for the next contingency in excess of the demand group allowance (currently load shedding is not permitted for demand groups greater 250 MVA).

Network design decisions resulting from the application of the planning criteria affect network operability and the ability to safely operate and secure the network under normal and abnormal network conditions. It is expected that network design decisions taken in planning timescales are aligned to the operational considerations below and as such lead to positive operability outcomes in the operational timescale:

- Under generation connection criteria, the power infeed loss risk limit of 400 MW will require the consideration of credible contingencies involving N-1 circuit breaker failures (clause 2.5.3.1 (3)) and N-1-1 busbar, transmission circuit or circuit breaker contingencies (clause 2.5.3.1(4) and 2.5.3.1(5)). It is expected that adherence to such criteria will drive the requirement for one and a half circuit breaker switchyard configurations and three or more interconnecting transmission circuits (subject to AEMO consultation) when connecting more than 400 MW of generation capacity. Operationally, this will provide more resilient generation connections and facilitate outages of transmission equipment when connecting new generation without the need for limiting the loss of generation capacity.
- Where Remedial Action Schemes are used to achieve compliance with transmission planning criteria or to avoid pre-contingent SCED runback, the design of the scheme must be capable of reliably operating under all credible system operating conditions and network configurations where a scheme response is required to ensure system security. Risk of interactions with other schemes, unintentional scheme operation and multiple remote contingencies initiating the scheme is to be avoided.
- In general, the planning of the Transmission System must be consistent with the operational criteria in Chapter 5 of the Technical Rules through planning for the following outcomes:
  - Providing sufficient network reinforcement, reactive capability and network control to enable the secure management of network voltage and power flows within Technical Rules limits.
  - Isolation of circuits or circuit elements should be achievable with as minimal switching as possible.
  - Multiple transmission connected customers sharing a single dedicated connection asset, or runback/tripped by a scheme in response to a single contingency is to be avoided where possible.
  - Creating networks that have significantly limited access windows such that single outages within those networks prevent the concurrent outages of many other circuits is to be avoided where possible.

4.8 Application Examples

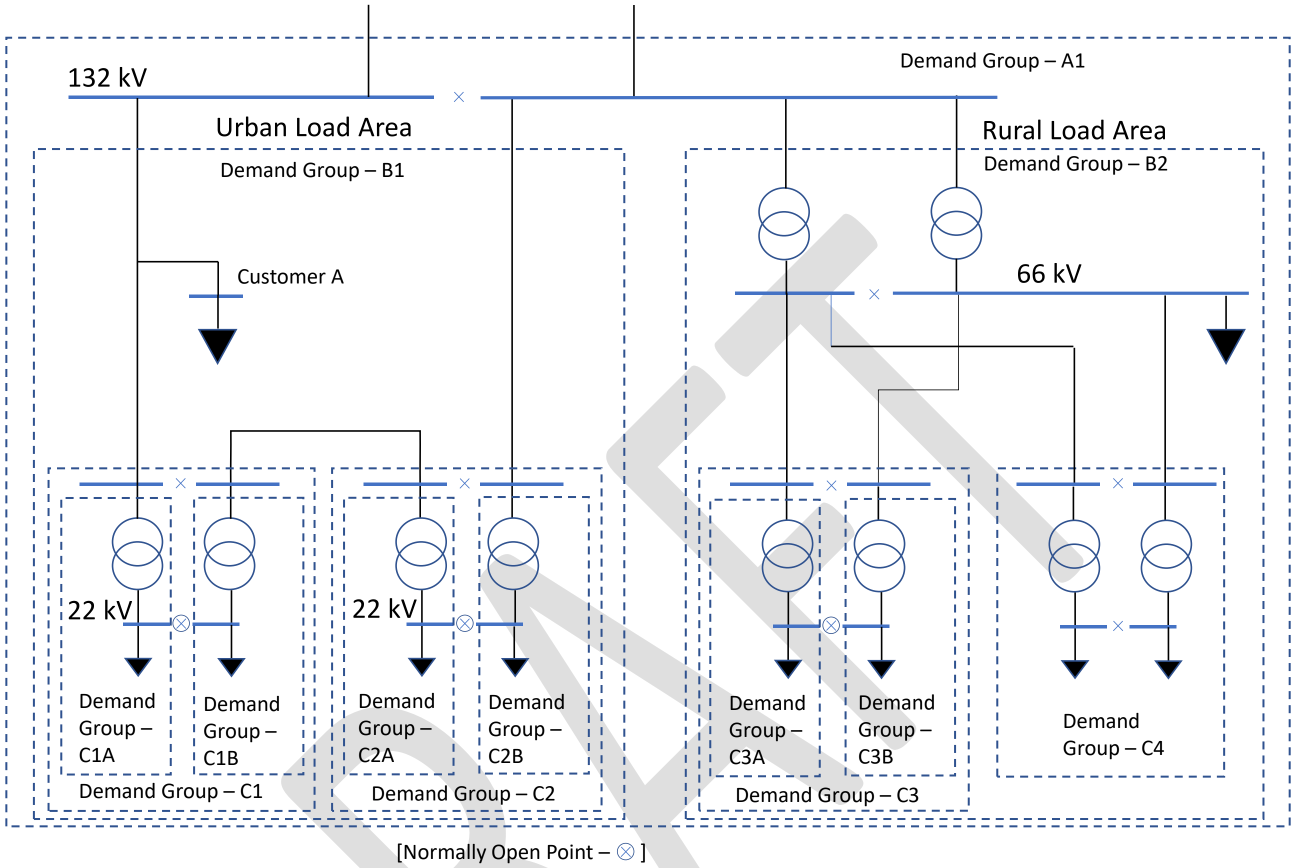
In general terms, a particular section of the transmission network will typically be composed of numerous demand groups, with lower voltage demand groups combining to form larger demand groups. This is illustrated in following **Error! Reference source not found.**.

From a review of **Error! Reference source not found.**. it is evident that the example section of the t ransmission network shown has the following characteristics:

- The network contains four individual demand groups (C1(A/B), C2(A/B), C3(A/B) and C4) relating to the supply of four zone substations.
- Three of the zone substations with split 22 kV busbars, i.e. C1(A/B), C2(A/B) and C3(A/B) also sit within wider C1, C2 and C3 demand groups that cover the full zone substation group demand.
- The fourth zone substation has closed 22 kV busbars and hence the applicable demand group (C4) covers the full substation load.
- Two zone substation demand groups (C1 & C2) form part of a larger B1 demand group covering an urban load area, which also includes connection to Customer A.
- A second pair of zone substation demand groups (C3 and C4) form part of a larger B2 demand group covering a rural load area, including a customer load supplied at 66 kV.
- The whole section of the transmission network, including demand groups B1 & B2 forms part of an overall demand group A1

The following sections provide a number of examples that demonstrate how group demand should be calculated and also whether in the particular examples themselves the transmission network would be compliant with the planning requirements detail in Table 2-10 of the Technical Rules.

Figure 1: Typical demand groups within a section of *transmission* network



Group demand example 1 – C1(A/B) and C2(A/B) demand groups

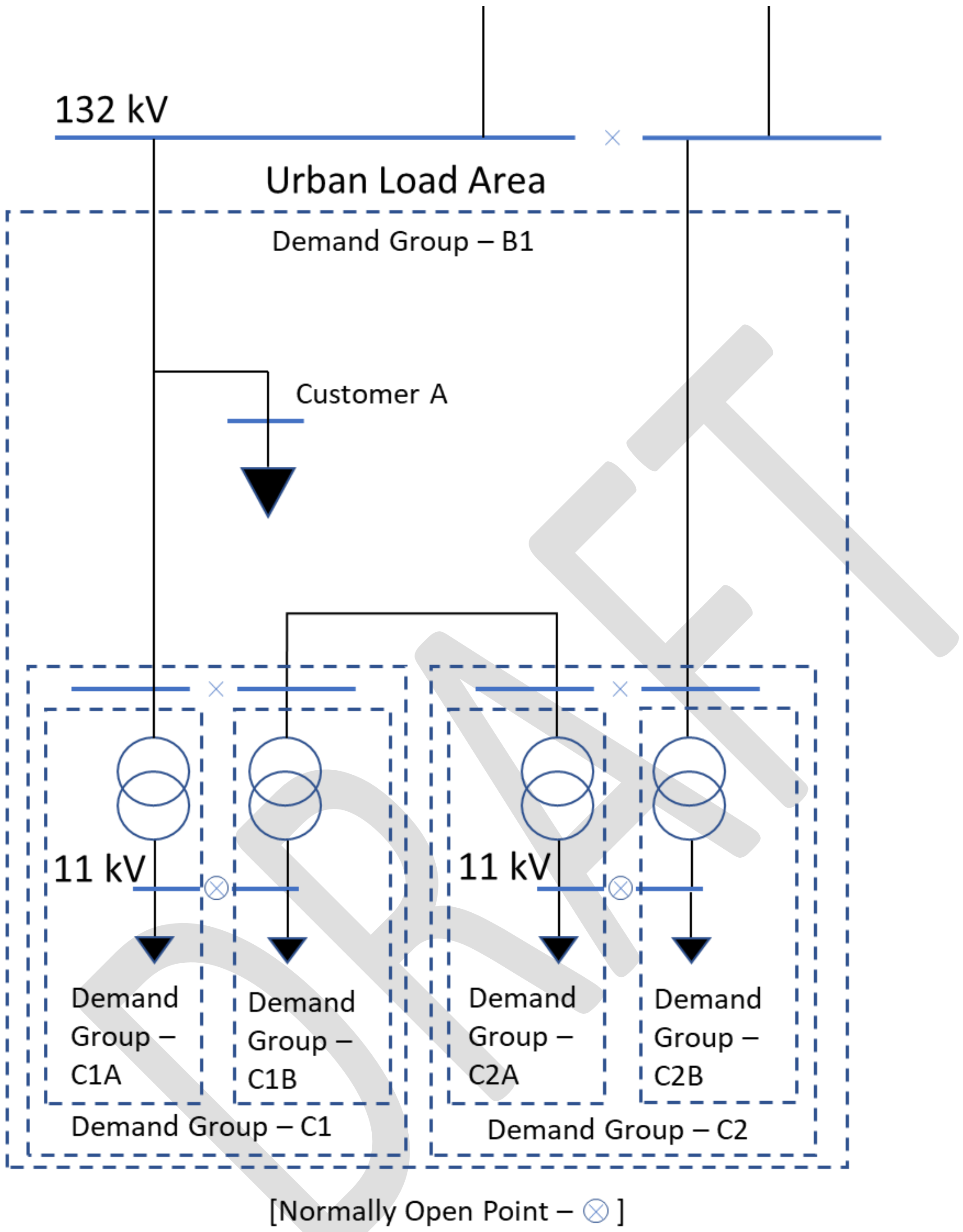


Figure 2: Demand groups C1(A/B) and C2(A/B)

This example considers demand groups C1(A/B) and C2(A/B) from the wider demand groups A1 and B1 shown in **Error! Reference source not found.**.

Consider the following characteristics for demand groups C1(A/B) and C2(A/B):

- Each is supplied by a zone substation with 2 x 30 MVA 132 / 22 kV transformers,
- Each substation has two 22 kV switchboards that share the load evenly but are normally open i.e. split,
- Each zone substation has 22 MW (24 MVA) of demand, 11 MW on each switchboard,

- No embedded generation is connected at 22 kV within either substation,
- Transfer capacity is 25 MW to neighbouring substations within demand group B1,
- A three ended circuit supplying demand group C1(A/B) also supplies Customer A, who has agreed to a single circuit supply.

The security of supply of the demand at each substation can be summarised by the following scenarios.

As the 22 kV switchboards are operated split at each zone substation:

1. The loss of an incoming 132 kV overhead line (from the upstream 132 kV substation) supplying either zone substation will not result in any loss of demand – provided that the interconnection at 132 kV to the neighbouring substation can supply the full load,
2. The loss of one zone substation transformer at either substation will result in a loss of demand, until one of the following actions is taken:
   – The 22 kV switchboards are operated closed,
   – The load supplied from the lost zone substation transformer can be transferred to the remaining healthy transformer or the neighbouring zone substation transformers through the distribution network,
   – The lost zone substation transformer is returned to service, either through repair or replacement.

Reviewing the requirements of Table 2-10 of the Technical Rules, the following conclusions can be made with regards to whether the above scenarios are compliant with the planning criteria.

- **Scenario 1 – loss of a transmission circuit**
  – In relation to scenario 1, as the total demand in each demand group C1 (including C1A and C1B) and C2 (including C2A and C2B) is <90 MVA each, with the initial conditions of an intact system then following the loss of an incoming transmission line from the upstream 132 kV substation the permitted demand is "None". That is, there must be no loss of demand. As noted, provided the transmission circuit connection to the neighbouring zone substation will allow the full substation load to be met, this design is compliant with the planning criteria.
  – However, if there was a limitation in the transfer capacity at 132 kV of either the interconnecting transmission circuit e.g., 15 MVA or the incoming transmission circuit from the upstream 132 kV substation e.g., 35 MVA, then this would not be compliant with the planning criteria as the remaining 132 kV transmission system would not be capable of supplying the total demand group C1 and C2 load (48 MVA).
- **Scenario 2 – loss of a zone substation transformer**
  – For scenario 2, following the loss of a zone substation transformer demand will be lost until restoration actions are taken. As per Table 2-10, as the zone substation load on each switchboard (12 MVA) is in an urban area and <60 MVA, then with the initial conditions of an intact system following the loss of a zone substation transformer the demand may be lost for the duration of "remote switching"[8]. If switching can be undertaken remotely then each of the substation demand groups C1(A/B) & C2(A/B) would be compliant with the planning criteria.

[8] This is intended to be switching performed from the Network Service Provider control centre and will allow the transformer and/or busbar on outage to be remotely isolated (if this has not already happened through associated protection system operation) and the to be reconfigured by closing the interlinking circuit breaker or any interconnecting feeders

- However, if either of the demand groups C1(A/B) or C2(A/B) is supplied from a substation that does not have remote 22 kV switching capability, the loss of a zone substation transformer would not be compliant with the planning criteria.

- In relation to Customer A, as they have agreed to a single circuit supply risk then following the outage of the three end circuit supplying demand group C1, the supply to Customer A is excluded from loss of energy calculations.

Group demand example 2 – C3(A/B) demand group

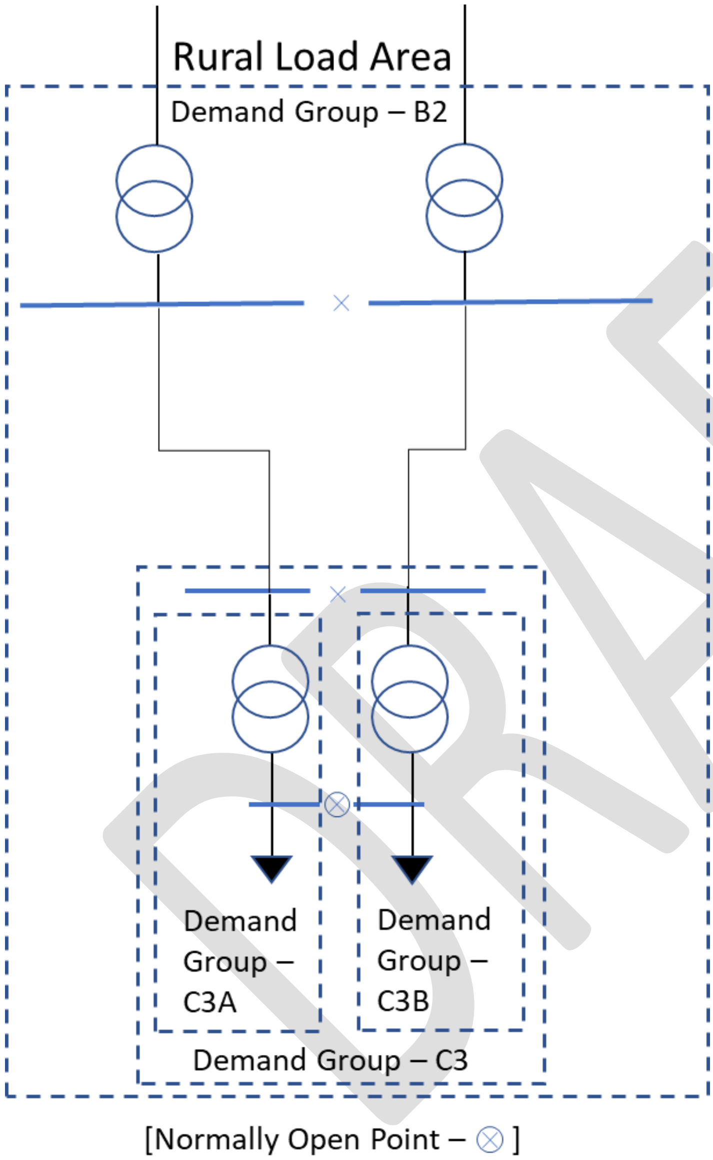


Figure 3: Demand group C3(A/B)

This example considers demand group C3(A/B) which is within wider demand groups B2 and A1 shown in **Error! Reference source not found.**.

Consider the following characteristics for demand group C3:

- The substation is supplied via 2 x 30 MVA 66 / 22 kV transformers,

- Each 66 kV busbar at the zone substation is supplied via a 66 kV overhead line from a terminal substation, with each line supplied from a different 66 kV busbar section at the terminal substation,
- The 66 kV busbars at the zone substation and terminal substation are operated closed i.e. in parallel,
- The substation has two 22 kV switchboards that share the load evenly but again are operated open under normal conditions i.e. split.
- No embedded generation is connected at 22 kV,
- There is no transfer capacity from other substations,

The security of supply of the demand at the substation can be summarised by the following scenarios.

1. The loss of an incoming 66 kV overhead line will not result in a loss of demand unless the remaining 66 kV line cannot supply the C3 group demand in full i.e. the combined C3A and C3B demand. If the remaining 66 kV overhead line cannot supply the C3 group demand in full, then demand will be lost until the overhead line on outage is returned to service either through repair or replacement. Note that there is no load transfer to other zones substations.
2. The loss of one zone substation transformer supplying either demand group C3A or C3B will result in a loss of demand until one of the following actions is taken:
   – The 22 kV switchboards are operated closed and the combined C3(A/B) group demand is supplied via the remaining transformer,
   – The zone substation transformer that experienced the outage is returned to service, either through repair or replacement.

Note that if the remaining zone substation transformer cannot supply the full combined C3(A/B) group demand then there will still be some loss of demand.

Reviewing the requirements of Table 2-10, the following conclusions can be made with regards to whether the above scenarios are compliant with the planning criteria.

- The requirements related to Rural demand groups apply as per Table 2-10 of the Technical Rules:
- **Scenario 1 – loss of a transmission circuit**
  – In relation to scenario 1, if the total C3 group demand is < 20 MVA then starting with the initial conditions of an intact system, following the loss of an incoming transmission line the C3 group demand can be lost for the duration of the "repair time" of the overhead line. So even if the remaining 66 kV overhead line in service was unable to supply the C3 group demand (combined C3A and C3B demand), this would still be compliant with the planning criteria.
  – However, if under scenario 1 the total C3 group demand was > 20 MVA then starting within an intact system, following the loss of an incoming transmission circuit no group demand is permitted to be lost. If the remaining 66 kV overhead line in service is able to supply the total C3 group demand then this meets the planning criteria requirements. However, if the 66 kV line has limited capacity and is unable to supply the total C3 group demand, then this would not be compliant with the planning criteria.
- **Scenario 2 – loss of a zone substation transformer**
  – Under scenario 2, the loss of a zone substation transformer will result in a loss of demand until either the affected transformer is repaired or replaced, or the 22 kV switchboard is operated closed. If the C3A or C3B group demand is < 10 MVA, based on Table 2-10, the requirement is to restore group demand with the "repair time" for the failed transformer.

– However, if the C3A (or C3B) group demand was ≥10 MVA, then the group demand must be restored through “remote switching” following the outage of a zone substation transformer.

- Additionally, based on Note 1 following Table 2-10 of the Technical Rules, if the contingency involves a zone substation transformer and the demand loss is > 20 MVA but < 60 MVA, then demand can be lost for up to 30 seconds. This will be sufficient time to perform remote switching and close the 22 kV circuit breaker between the two 22 kV switchboards to restore supplies. However, if this switching cannot be performed within the 30 seconds timeframe then this would not be compliant with the planning criteria.

Group demand example 3 – C4 demand group

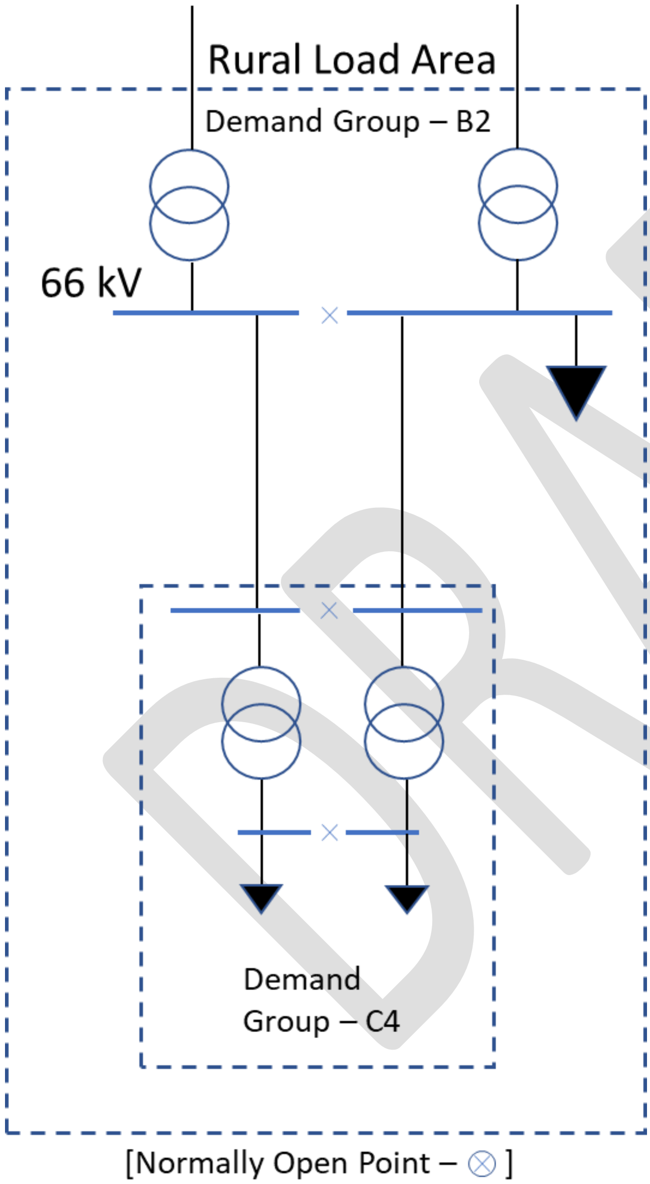


Figure 4: Demand group C4

This example considers demand group C4 which is within wider demand groups B2 and A1 shown in **Error! Reference source not found.** and is similar to the demand group C3 example except that the 22 kV zone substation switchboards are operated as closed i.e. in parallel.

This change in 22 kV switchboard configuration has the impact that the total zone substation load is now considered as one demand group (C4) as parallel assets i.e. two zone substation transformers, two 66 kV busbar sections and incoming 66 kV overhead lines, supply the entire combined C4 group demand.

In terms of the impact of this revised 22 kV switchboard configuration:

1. The loss of an incoming 66 kV overhead line will not result in a loss of demand. The security of supply of the C4 group demand with respect to incoming 66 kV overhead line capacity is the same as detailed for the C3 demand group as the 66 kV configuration is the same.
2. The loss of one zone substation transformer will not result in a loss of demand within the C4 demand group unless the remaining transformer is unable to supply the total C4 demand.

In relation to whether the above scenarios are compliant with the planning criteria.

- **Scenario 1 – loss of a transmission circuit**
  - In relation to scenario 1, the same comments and limitations noted for the C3 demand group also apply to the C4 demand group i.e. the restoration requirements in relation to 66 kV overhead line outages varies depending on the total C4 group demand and whether this less than or greater than 20 MVA.
- **Scenario 2 – loss of a zone substation transformer**
  - Under scenario 2, the loss of a zone substation transformer will not result in a loss of demand as long as the C4 group demand is supplied in full. If the full C4 group demand cannot be supplied on one zone substation transformer:
    - If the C4 group demand is <10 MVA then it is permissible for demand to be lost for the duration of "Repair Time".
    - If the C4 group demand is ≥ 10 MVA and < 60 MVA then it is permissible for demand to be lost for the duration of "remote switching".
    - However, if as in this example, there is no neighbouring substation to transfer the demand to then operating the C4 zone substation such that the full load cannot be supplied by a single transformer would not be compliant with the planning criteria.

Group demand example 4 – B2 demand group

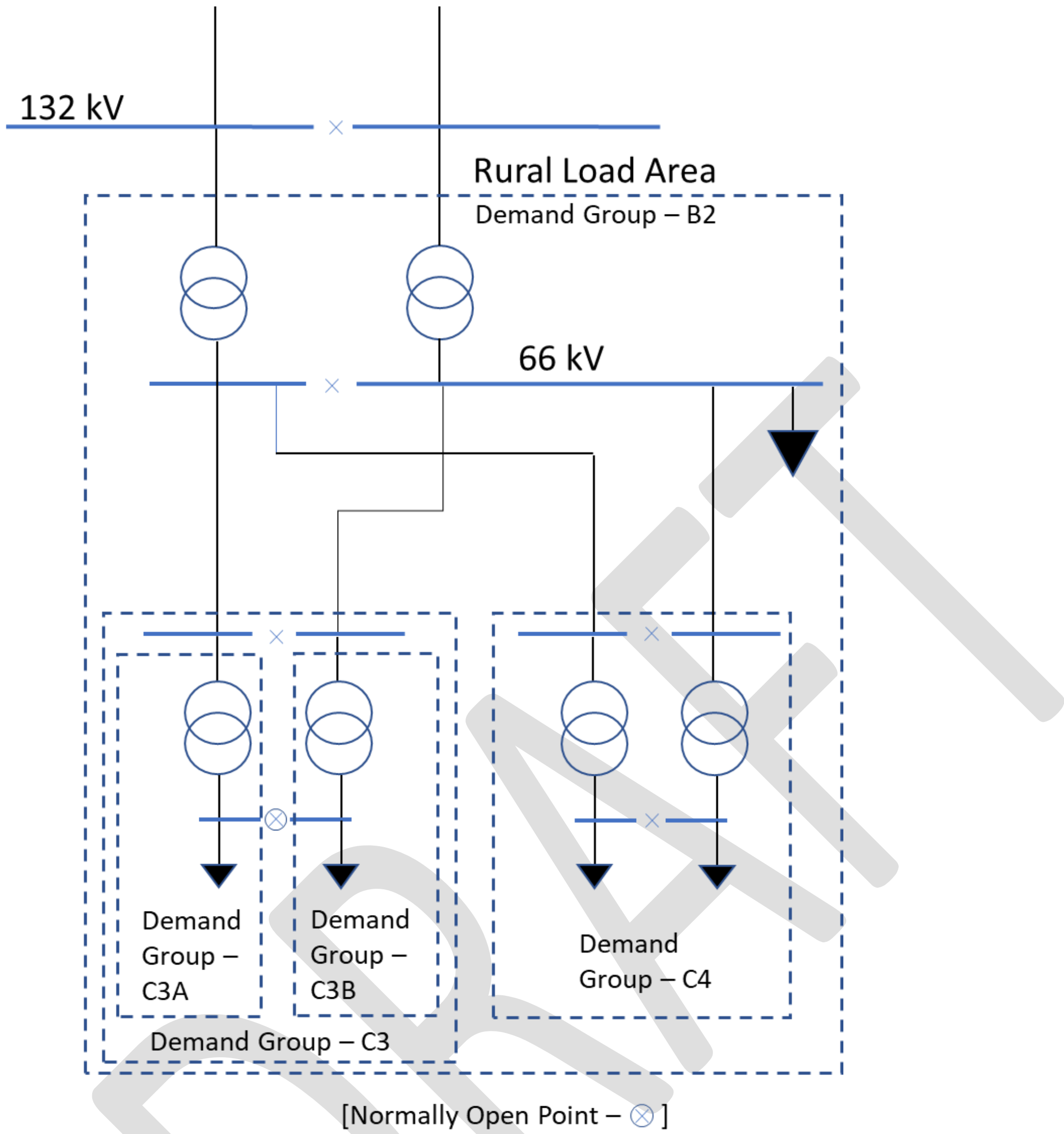


Figure 5: Demand group B2

This example considers demand group B2, shown in **Error! Reference source not found.**, which is within w ider demand group A1 shown in **Error! Reference source not found.**.

Consider the following characteristics for demand group B2:

- The demand group is supplied by two bus-tie 132 / 66 kV transformers each rated at 90 MVA,
- Both bus-tie transformers are supplied from the same 132 kV busbar, with each transformer connected to a separate 66 kV busbar which are operated closed i.e. in parallel.
- The total demand includes demand group C3 and C4 at 25 MVA each plus a 45 MVA customer load supplied from the 66 kV busbar at the terminal substation via a single circuit (not shown).
- There is no transfer capacity from other substations.

The security of supply of the demand within demand group B2 can be summarised by the following scenarios.

1. The outage of one bus-tie transformer will not result in any loss of demand to the 66 kV network, as the total demand can be supplied through the remaining bus-tie transformer.
2. The outage of the 132 kV busbar to which the bus-tie transformers are connected will result in the loss of the full demand group, until:
   – The outage of the 132 kV busbar is restored, with the busbar plant and equipment being repaired / replaced as necessary,
   – The bus-tie transformers are switched to an alternative 132 kV busbar section unaffected by the first outage – depending on the substation configuration, this may be achieved automatically or through "remote switching"[8] actions.
3. The loss of one section of 66 kV busbar, and hence one bus-tie transformer, will result in the loss of demand to the downstream demand group(s) if:
   – the remaining bus-tie transformer cannot supply the full downstream combined demand,
   – the remaining 66 kV overhead lines cannot supply the individual downstream demand.

   this will be the case until:
   – the 66 kV busbar fault is addressed,
   – the affected 132 / 66 kV bus-tie transformer connected to the faulted 66 kV busbar section is transferred to the healthy 66 kV busbar section; or
   – the affected outgoing 66 kV transmission circuits, connected to the faulted 66 kV busbar section, are transferred to the healthy 66 kV busbar section.

Reviewing the requirements of Table 2-10, the following conclusions can be made with regards to whether the above scenarios are compliant with the planning criteria.

- The requirements related to Rural demand groups apply as per Table 2-10.
- in relation to scenario 1, if the total demand exceeded 90 MVA as stated in the example, then the loss of a bus-tie transformer would not satisfy the outlined requirements. Even though the customer connected at 66 kV has agreed to single circuit risk, unless otherwise agreed, this would normally only apply to their dedicated connection circuit. As a result, the full demand group B2 load will still need to be secured (no loss of demand) following the outage of a bus-tie transformer.
- Note that as per the definitions that follow Table 2-10, the outage of a bus-tie transformer is considered within the TCT, Transmission Circuit contingency category.
- Further in relation to scenario 1, if the total demand in demand group B2 is <90 MVA, then the requirements for the ≥ 20 MVA & < 90 MVA demand group (no loss of demand) should be met, which would be, if demand was <90 MVA.

With respect to scenario 2, as the total demand in demand group B2 exceeds 90 MVA, then a busbar outage, at 66 kV or 132 kV, is considered a credible contingency and hence the demand group would have to be designed to comply with the requirements of the ≥ 90 MVA & < 250 MVA demand group as per Table 2-10.

However, if the demand was <90 MVA, the ≥ 20 MVA & < 90 MVA demand group rules would be applied, as defined in Table 2-10. These requirements do not include busbars within the credible contingency category, whether 66 kV or 132 kV. As a result, the total demand within demand group B2 of <90 MVA, there is no requirement to design the transmission network to recover this demand following a contingency involving 66 kV or 132 kV busbars.

Taking the outlined Example 4, if the bus-tie transformers were rated at 120 MVA (instead of 90 MVA) and the total Group B2 demand is unchanged, then a credible contingency involving a 66 kV busbar will not meet the requirements of Table 2-10 unless:

- the outage of the busbar would not lead to any demand loss within demand groups C3 and C4, or
- the 66 kV busbars are configured in a double busbar (or alternative) configuration to avoid an outage of the outgoing 66 kV transmission circuits or bus-tie transformer during a 66 kV busbar fault.

Finally, in relation to scenario 2, if the total B2 group demand > 90 MVA then a contingency involving a 132 kV busbar fault at the terminal substation will also not be able to meet the requirements of Table 2-10, unless the bus-tie transformers are supplied from different 132 kV busbar sections such that an outage of one 132 kV busbar section can be isolated without disconnecting the other busbar section. This will be the case even if a single bus-tie transformer is able to supply the total B2 group demand.

In summary, for demand group B2 whether this group can meet the planning criteria requirements will depend on:

- The total value of the B2 group demand i.e. whether greater than or less than 90 MVA,
- How the 132 kV and 66 kV busbars at the terminal substation connecting the bus-tie transformers are configured,
- The rating of the zone substation transformers, and whether these can supply the total B2 group demand,
- The rating of the outgoing 66 kV overhead lines supplying the downstream zone substations – depending on the 66 kV busbar configuration.

For the B2 demand group to meet the planning criteria all applicable contingency elements i.e. transmission circuit, zone substation transformers, busbars, must all meet the applicable requirements otherwise the demand group will not meet the planning criteria.

5. Contingency Criteria

5.1 Background

A power supply network must operate during planned and unplanned outages of plant and equipment, due to faults or maintenance requirements. Contingency Criteria are provided to define the number and type of outages that need to be allowed for in designing various parts of the transmission and distribution networks. This implies a degree of reliability associated with the various parts of the network.

The contingency criteria also guide the determination of substation capacity.

Clause 2.5 of the Technical Rules outlines the contingency criteria applicable to the planning of the transmission network, including substation capacity. Of particular relevance for this Transmission Planning Guideline document are the following sections of the Technical Rules:

- Generation connection criteria – section 2.5.3.
- Demand connection criteria – section 2.5.4.
- Main Interconnected Transmission System (MITS) and sub-transmission– section 2.5.5.

In the following subsections details are provided of the specific plant and equipment contingencies that are considered credible with respect to planning the various functional elements of the transmission system as well as other network planning and substation design considerations that the Network Planner should be cognisant of.

5.2 Credible Contingencies

An overview of the specific requirements of the above sections of the Technical Rules has been presented in Section 4 of this Guideline. As noted, the Technical Rules summarises under each functional area the specific plant and equipment planned and fault outage events that are considered credible with respect to planning each functional area. A summary of the planned and fault outage events that are considered credible are presented in Table 3.

Table 3: Summary of Credible Contingency Events within Transmission Planning Criteria

<table>
<tr><th>Contingency Element</th><th>Generation connection</th><th>Demand Connection</th><th>MITS Planning</th></tr>
<tr><td>Single zone substation transformer</td><td rowspan="6">Starting from intact system conditions, AND Starting with local system outage</td><td rowspan="6">Starting from intact system conditions, AND Starting with local system outage</td><td>N/A</td></tr>
<tr><td>Single transmission circuit</td><td rowspan="5">Starting from intact system conditions, AND Starting with local system outage</td></tr>
<tr><td>Single generation circuit*</td></tr>
<tr><td>Single generator unit</td></tr>
<tr><td>Single item of reactive equipment</td></tr>
<tr><td>Section of busbar</td></tr>
<tr><td>Single circuit breaker</td><td>N/A</td><td>As part of local system outage only</td><td>As part of local system outage only[9]</td></tr>
</table>

As seen in Table 3, for all three major functional areas of the transmission system the same transmission elements are considered as credible contingencies in most areas, either as a fault outage starting from an

[9] In addition to this, the MITS should be planned that a single circuit breaker failure when the system is <80% of peak load does not cause a non-complaint system as per clause 2.5.5.3 (b) of the Technical Rules.

intact transmission system, or as a planned outage following which a fault outage occurs. Note that in the case of the latter, all combinations of planned and fault outages should be studied, the exception is in relation to a single circuit breaker outage which is considered as a credible planned outage only. It should also be noted that:

- for generation connections, an explicit list of planned outages that conform to “local system outage” are not stated as only those that have a direct effect on the generation connection should be studied, which will vary on a case by case basis.
- Zone substation transformers are also not considered as credible outages, either as a fault or planned outage, with respect to planning of the MITS.
- For the Perth CBD, the applicable system conditions are: starting from an intact system; starting with a local system outage; and starting with a local fault outage.

In addition to the requirements presented in Table 3, a circuit breaker failure as a result of a single phase to earth fault (if occurring at less than 80% of expected transmission system peak load) is also considered as a credible contingency with respect to MITS planning.

5.3 Planning Application

5.3.1 General

The Technical Rules provide for different parts of the transmission network to be designed to different levels of reliability. The intent is to provide higher integrity to the more important parts of the network. The parts of the network demanding higher integrity are those parts where a failure could result in system collapse, or where a disturbance could have far reaching impacts across the customer base.

Historically, the importance of parts of the network has been directly linked to the operating voltage of that part of the network. Recent developments that have resulted in higher utilisation for 132 kV systems and extension of 330 kV networks into remote regions will require this approach to be refined.

In applying contingency criteria, the network capability is assessed under peak load conditions (unless alternative conditions are specified in the criteria). The System Forecasting Section of the Network Planning and Development Branch produces the peak demand forecasts used in planning studies. Transmission planning studies use PoE forecasts (see Section 4.5 of this Guideline) which ensure that the transmission network is planned to have sufficient capacity to cope with the varying probability of the occurrence of each scenario, including one year in ten peak demands.

In assessing network capability, the appropriate basis for forecasting peak load needs to be identified. Peak load may be for an individual substation, a group of substations, or the system as a whole. Substation and system peak load forecasts are produced annually for each substation. Substation peak load forecasts are to be used for assessing substation capability. System peak load forecasts, as defined under the System Security scenario are to be used for assessing the network as a whole. When assessing small parts of the network consideration needs to be given to an appropriate forecast to be used. In some instances, it may be necessary to produce a specific forecast for that area.

5.3.2 Network Planning and Substation Design

The contingency criteria outlined in the Technical Rules for demand connections are extensive; each component of the contingency criteria is addressed below.

N-0 Criterion

The N-0 criterion applies to demand groups that are small (lightly loaded) and generally in remote parts of the transmission network. The Technical Rules specify that the N-0 criterion applies to the following demand groups:

- less than 10 MVA for credible contingencies involving zone substation transformers; and
- less than 20 MVA for credible contingencies involving transmission circuits.

In addition, some major customers have elected to be provided with an N-0 supply.

The N-0 criterion allows that in the event of the loss of a single element of the transmission network (zone substation transformer or transmission circuit), supply may be lost. It also notes that supply will not be restored until that element can be returned to service (following maintenance, repair, replacement). This is the stated "Group demand for repair time".

The complete loss of supply to an entire area is recognised to be onerous for the affected community, especially if it affects essential services.

For the Eastern Goldfields, the N-0 criterion is moderated by the requirement that back-up generation of sufficient capacity be available to supply town loads connected to that system. The intention here is that supply is provided to essential services, residential and commercial customers. No allowance is made to supply any of the local mining loads. This is permitted under the revised planning criteria for rural demand groups ≥10 MVA & <60 MVA for zone substation transformers contingencies and ≥20 MVA & <90 MVA for transmission circuit contingencies where group demand can be lost for the duration of remote switching time (former) or up to 60 MVA of group demand can be lost for the remote switching time following a contingency event involving a transmission circuit e.g., 220 kV overhead line, where it is not economic to fully secure it (latter). For guidance refer to Section 4.6 of the Guideline.

For other areas where the N-0 criterion applies, there is a requirement that best endeavours are made to provide some supply restoration through load transfer from adjacent areas. Where load cannot be fully backed-up load shedding may be used.

Although not a stipulated requirement under the Technical Rules Western Power does apply a "best endeavours" approach with respect to system and network reinforcement planning and in operation timescales. In this context, Western Power's interpretation is as follows:

- In system planning work, decisions are made based on cost and benefit. Best endeavours are taken to mean that where a decision can be made that will enhance the potential to support an N-0 load, without additional cost, this benefit should be recognised and incorporated into that decision.
- In operational work, best endeavours are taken to mean providing an alternative (potentially lower capacity) supply, within reason. This may mean providing temporary back-up generation or relocating plant from elsewhere to cover a long term loss of plant.

Best endeavours will also apply to load-shedding decisions. In general, decisions regarding load shedding are managed by AEMO and subject to the procedures outlined in the WEM Rules. It is best practice to provide supply to all essential services first, before the general customer base. In extreme circumstances, load minimisation requests to customers are effective ways of enabling a small amount of supply to be maintained for the broadest number of customers.

Alternative supply is not normally made available to major customers who have elected to be supplied by an N-0 connection.

N-1 Criterion

The N-1 criterion is the default criterion applied to the majority of the demand groups within the transmission network. Under the N-1 criterion, supply must be maintained, and unacceptable voltage conditions and system instability avoided following the loss (planned or unplanned) of any single transmission network element (as specified in Table 3).

System performance criteria such as harmonic content, flicker, and negative phase sequence do not have to be met under these conditions. These criteria are all measured on a long term basis and are not appropriate under outage conditions. Extensive costs would be involved in meeting these criteria under outage conditions.

Individual outages that apply to credible contingency events are specified in the Technical Rules in Section 2.5, and has been summarised in Table 3). Note that for double (or multiple) circuit transmission lines, a single transmission element means an outage of one circuit only.

For busbars where there are a number of sections separated by circuit breakers, a single element outage means an outage to one section of the busbar only.

The majority of Western Power's zone substations are operated with the low voltage busbars split (to reduce fault levels on the distribution network). Therefore, an outage of a zone substation transformer would result in an outage of any load supplied by that transformer. The Technical Rules recognise this and provide a provision for "remote switching time" which allows a brief loss of load until busbar switching enables load to be restored via the other transformers at that site. The time taken for switching will be dependent on the type of substation, but for this caveat to apply the switching must be able to be undertaken remotely from the Western Power network control centre. Most new substations contain indoor LV switchboards with remotely switched bus section breakers where restoration of supply could be expected within a few minutes. Older outdoor substations only contain disconnector switches along the busbars and site attendance by a switching operator would be required before supply could be restored. In these cases, restoration of supply could be expected to take up to a few hours.

The Technical Rules require that the N-1 criterion must be met for any load and generation condition. In applying this requirement, it is essential that consideration be given only to scenarios that may realistically arise i.e. credible load and generation patterns. Details on the approach and assumptions to be adopted with respect to generation dispatch and scheduling are detailed in Section 3.2 of this Guideline.

To meet the N-1 criterion, a number of generators have been allowed to connect to the network only after implementation of automatic run-back schemes. For these installations a transmission outage may require the output of a generator to be reduced.

N-1-1 Criterion

The N-1-1 criterion provides a higher degree of security than the N-1 criterion. In the context of the transmission planning criteria, it means overlapping planned and unplanned outage (not two successive fault outages).

The N-1-1 criterion is applied to the most important and largest demand groups within the transmission network, where an outage could put the system at risk, or could affect a large proportion of customers.

The Technical Rules require that the N-1-1 criterion applies to demand groups in excess of 250 MVA. In practice, this encompasses the previously defined areas of the transmission cover under the previous Technical Rules, such as:

- 330 kV lines, substations and power stations;

- 132 kV terminal stations in the Perth metropolitan area, and the Muja power station a 132 kV substation;
- 132 kV transmission lines that supply a sub-system of the transmission system comprising more than 5 zone substations (with total peak load exceeding 400 MVA); and
- power stations whose total rated export to the transmission system exceeds 600 MW.

In addition, as the criterion applies to all demand groups > 250 MVA, it is potentially possible that higher capacity zone substation, or 132 kV transmission circuits supplying multiple zone substations could also fall within this definition. This includes, for example Mason Road Substation and the transmission circuits that supply it and downstream load centres e.g., Waikiki, Rockingham.

Under the N-1-1 criteria, the network must be capable of maintaining supply to loads and of meeting the system performance criteria e.g., avoiding system instability, equipment overloading o unacceptable frequency conditions following the planned outage of one transmission element and the subsequent unplanned outage of a second element. Any part of the network operating under the N-1-1 criterion must also meet the requirements of the N 1 criterion.

The Technical Rules specify the combinations of outages that are included under the N-1-1 criterion.

The N-1-1 criterion applies only for loads up to 80% of peak load and allows for generation to be rescheduled. These allowances are made under the assumption that a planned outage would not normally proceed if load was forecast to exceed 80% of peak, and that it is reasonable to modify generation scheduling under lower load and plant maintenance conditions.

Given the increasingly “peaky” nature of Western Power’s load base, the 80% limit may not be appropriate in all conditions, hence the latest version of the Technical Rules stipulates that 80% should only be used if better data is unavailable. Managing N-1-1 on the bulk network is easier than some metropolitan areas due to the ability to effectively use generation to modify power flows and therefore retaining the 80% level at 132 kV is sometimes more onerous than for 330 kV.

Perth CBD Criterion

A special criterion is specified for the Perth CBD area in recognition of the economic importance of loads located in this small area to the conduct of business throughout the state.

The Technical Rules define an area known as the Perth CBD and supplies to all loads located within that area must comply with the Perth CBD criterion. This criterion requires that all loads must maintain full supply in the event of any of the following outage combinations (including all planned and unplanned combinations i.e., N-2):

- One or two transmission lines;
- One or two transformers;
- One transmission line and one transformer.

To fully meet the Perth CBD criterion, outage combinations considered should also include the elements set out in Section 5.2 of this Guideline.

As the CBD network does not operate as a paralleled network, it is recognised that load will be lost following the unplanned outages. The Technical Rules require that in these circumstances load must be restored within 30 seconds if a single transformer trips. For outages of multiple items of plant, load must be restored within 2 hours.

To comply with the 30 second requirement following loss of a transformer, each substation supplying the Perth CBD area is equipped with an automatic load switching scheme. Feeders and busbars supplying the CBD area must have spare capacity retained to pick up any automatically switched load that can result from a transformer outage. In the case of a substation outside the CBD area e.g., Cook Street which supplies load within the CBD area via distribution feeder(s), that substation needs to comply with the Perth CBD Criterion to the extent required to meet the CBD portion of its load.

6. Technical Performance Requirements

This section sets out the specific technical performance requirements that should be followed when planning the SWIS, including demand and generation connections. Guidance is provided of specific planning aspects that should be considered with respect to each of the outlined technical performance criteria.

Extensive reference is made to Section 2.2 Power System Performance Standards of the Technical Rules. Where relevant to aid understanding of specific requirements, extracts of individual clauses or requirements of the Technical Rules are represented here, however in broad terms this Guideline assumes that the reader is familiar with Section 2.2 of the Technical Rules and hence wholesale repetition of large sections of the Power System Performance Standards is avoided.

6.1 System Frequency

6.1.1 Overview of Technical Requirement

Frequency limits are imposed primarily to ensure network security and also to protect equipment from damage that would result from prolonged operation at frequencies outside their design range.

Frequency in the power system must be controlled to ensure the stability of generation connected to the network. Generators are designed to operate within tight frequency margins and protection will trip them if these are breached. While generators are capable of operating within a range around their design frequency, doing so will cause stress to the machine, which will accumulate and cause damage over time.

It is also important to maintain consistent power system frequency as numerous devices and systems rely on the power system frequency for time regulation.

Frequency is controlled through the provision of sufficient generation to meet load demand. If there is insufficient generation, frequency will start to decrease. If there is excess generation, frequency will increase. For the management of under-frequency events an automatic Under-Frequency Load Shedding (UFLS) specification is implemented by Western Power in accordance with clause 3.6.9 of the Wholesale Electricity Market (WEM) Rules.

The Technical Rules contain a number of criteria relating to frequency limits, control and management.

- Clause 2.2.1 stipulates the frequency limits that apply to operation of the power system, which are as specified in Section 3B.2 of the WEM Rules.
- Clause 2.4 provides detail regarding the Network Service Provider responsibility for developing the UFLS specification document. This clause also includes a requirement for Users to make a proportion of their load available for load shedding (whether under-voltage or under-frequency) as required by the NSP.
- Further details of User requirements in relation to the provision of load shedding facilities is presented in Section 3.4.9 of the Technical Rules. This includes requirements in relation to User co-operation with the NSP and application of specific UFLS relay settings.

Further requirements in relation to Under Frequency Management, including aspects that are relevant to both the NSP as well as AEMO are detailed in Section 3.6 of the WEM Rules.

6.1.2 Planning Application

Planning & Design Considerations

System frequency is of particular interest in planning studies related to the connection of new generators or new large loads. The performance of generators under adverse system conditions as well as the effect of the connection or sudden disconnection of load or generation in a particular location in the network is of interest. When planning generation and demand connections, considerations related to loss of generation infeed and load rejection are relevant aspects that must be considered as both have the ability to impact on the wider power system frequency. Section 2.5.3 of the Technical Rules covers generation connections and stipulates the maximum permitted loss of infeed risk for generation connections in order to remain with the Frequency Operating Standard as defined in the WEM Rules. This is currently 400 MW and effectively sets the limit as to the maximum total capacity of generation capacity that is permitted to be disconnected following a credible contingency event.

For demand connections Section 2.5.4 of the Technical Rules covers the relevant design and planning considerations, including setting out the permitted levels of security and redundancy that apply to demand connections. This includes for demand groups in excess of 250 MVA that the demand is fully secure for a credible contingency of a fault outage during a planned outage (N-1-1) that affects the supply security to the demand group. In essence this places a limit on the maximum load rejection event that is permitted when planning and designing demand connections in order to limit the concomitant impact on power system frequency response.

In addition to the specific requirements and planning consideration that apply to generation and demand connections system frequency should also be considered when studying the wider Main Interconnected Transmission System (MITS), where demand security is also considered, as well as other parts of the sub-transmission system. For this latter area of the power system, specific consideration may need to be given to parts of the transmission network where there is little redundancy and system faults could result in either the disconnection of large amounts of load or generation or the creation of an 'island[10]' within the network, potentially upsetting the load-generation balance both within the island and across the wider power system. Areas where islanding is known to be possible are the Eastern Goldfields and the North Country networks. Other island conditions may develop over time as the network and generator connections change.

Further details of the planning and design connection requirements are presented and discussed in Section 4 of this Guideline.

Frequency Operating Limits

As noted under Section 6.1.1 of this Guideline, the frequency operating limits that apply to SWIS and a power island within the SWIS are detailed in clause 3B.2 of the WEM Rules. These are set out in Table 1 (SWIS) and Table 2 (isolated power islands) of Appendix 13, with each covering a number of defined frequency operating conditions. These are shown below for the SWIS (taken from Table 1):

- Normal Operating Frequency Band (NOFB): range 49.8 – 50.2 Hz (for 99% of time over any 30-day period)
- Normal Operating Frequency Excursion Band (NOFEB): range 49.7 – 50.3 Hz, return to NOFB within 5 minutes

[10] An island is created when one part of the transmission network becomes completely isolated from the remainder of the network. It is possible for an island to operate satisfactorily, independent of the main network if there is a generation supply and control mechanisms to manage the load within the generation capability.

- Credible Contingency Event Frequency Band (CCEFB): range 48.75 – 51.0 Hz, return to <50.5 Hz within 2 minutes (for over-frequency events), return to NOFB within 15 minutes
- Island Separation Frequency Band (ISFB): range 48.75 – 51.0 Hz, recovery as per CCEFB
- Extreme Frequency Tolerance Band (EFTB): range 47.0 – 52.0 Hz[11], return >47.5 Hz within 10 seconds[11] (under-frequency events), return to < 51.5 Hz within 1 minute and <51.0 Hz within 2 minutes[11] (over-frequency events). Return to 48.0 - 50.5 Hz within 5 minutes[11].
- Rate of Change of Frequency Safe Limit (RoCoF Limit): 0.5 Hz / s (measured as 0.25 Hz over any 500 ms period)

These limits and the time periods associated with each are intended to limit the stress upon generating machines, to prevent long term damage. Off frequency operation of generators with no immediate damage is possible, but the stresses caused by this accumulate with time.

Severe system disturbances may lead to parts of the system separating into islands. When this occurs, it is inevitable that there will be a degree of load/generation mismatch. In these circumstances it is desirable for each island to reach a state of equilibrium with minimal unintentional loss of load. Special UFLS schemes may need to be implemented in parts of the network where there is a relatively high risk of islanding occurring. The defined frequency operating conditions for islanded parts of the interconnected transmission system are set out in Table 2 of the WEM Rules.

Power Quality Considerations

The Technical Rules also specify a range of power quality parameters that the NSP must ensure are monitored across the power system. This includes system fundamental frequency, which should be measured on a continuous basis (as a mean value over the sampling interval) over a 10 second data sampling interval.

6.1.3 Frequency Management

To aid frequency recovery following an under-frequency event, UFLS facilities are installed at most zone substations within the SWIS. Load shedding requirements are set out by AEMO in their published UFLS Requirement document (as detailed in clause 3.6.1 of the WEM Rules) with Western Power developing a specific UFLS implementation schedule which is documented in the UFLS Specification (as defined under WEM Rules clauses 3.6.6). The UFLS Specification document details the five stages of the load shedding scheme, which commences at 48.75 Hz and trips 15% of total system load and precedes through four further stages each at 0.25 Hz intervals (and tripping a further 15% of system load each) with the final stage occurring at a system frequency of 47.75 Hz.

Western Power is responsible under the WEM Rules (as Network Operator) for the implementation of the outlined UFLS specification and must determine which specific feeders are to be included in the UFLS scheme and critically at which stages (and trigger frequency). All future zone and customer substations are required to include UFLS facilities. In addition, there is a requirement that capacitor banks be included in the load shedding schemes. This is required to prevent possible voltage instability resulting from frequency related load shedding incidents where network load is shed but the corresponding capacitor banks which are improving system voltages or providing power factor correction are left in service.

Regular review of the UFLS scheme implementation is required by Western Power (network-wide and area specific) to ensure adequate load shedding response and to ensure that frequency stability is achieved. Such reviews will be necessary following significant increases in system load as a result of demand growth

[11] Reasonable endeavours

or new load connections or further as a result of changes made by AEMO to the published UFLS Specification.

In parts of the network where there is the possibility of islanding occurring, specific additional UFLS schemes are installed. The performance of these UFLS schemes within islands needs to be reviewed for performance during both system wide frequency excursions and island situations.

Under-frequency events can be managed through the use of UFLS schemes. Over-frequency events on the other hand can only be managed through generator control. During high load conditions where there are many heavily loaded generators connected to the network, this is straightforward as generators have the capability to reduce load based on governor droop response and can be instructed by AEMO as necessary. However, during light load conditions (particularly overnight) fewer generators are connected and many of these are at or close to their minimum output. There will therefore be little capability to reduce output to match a reduced load.

The potential for over-frequency events to arise following the connection of large new loads also require consideration. As part of the Transmission Planning Criteria specific security and redundancy requirements relating to demand connection are specified. This includes an effective limit of 250 MVA as the largest loss of load that can occur due to a single contingency event and places a limit on the effective over-frequency step change that can occur. Specific design considerations with respect to demand connections are covered under Section 4 of this Guideline.

6.1.4 Supporting Material – Consequences of Inadequate Frequency Control

The consequences of prolonged operation at less than nominal system frequency include damage to generating plant (through over fluxing) and malfunction of some frequency dependent equipment and devices. There may also be damage to turbine blades through accumulation of stress or resonance.

Operating at higher than nominal frequency causes the generator to run at over speed, which stresses the turbine shaft and in severe cases will result in the shaft breaking. To avoid this, several mechanical safety mechanisms are usually built into the machines.

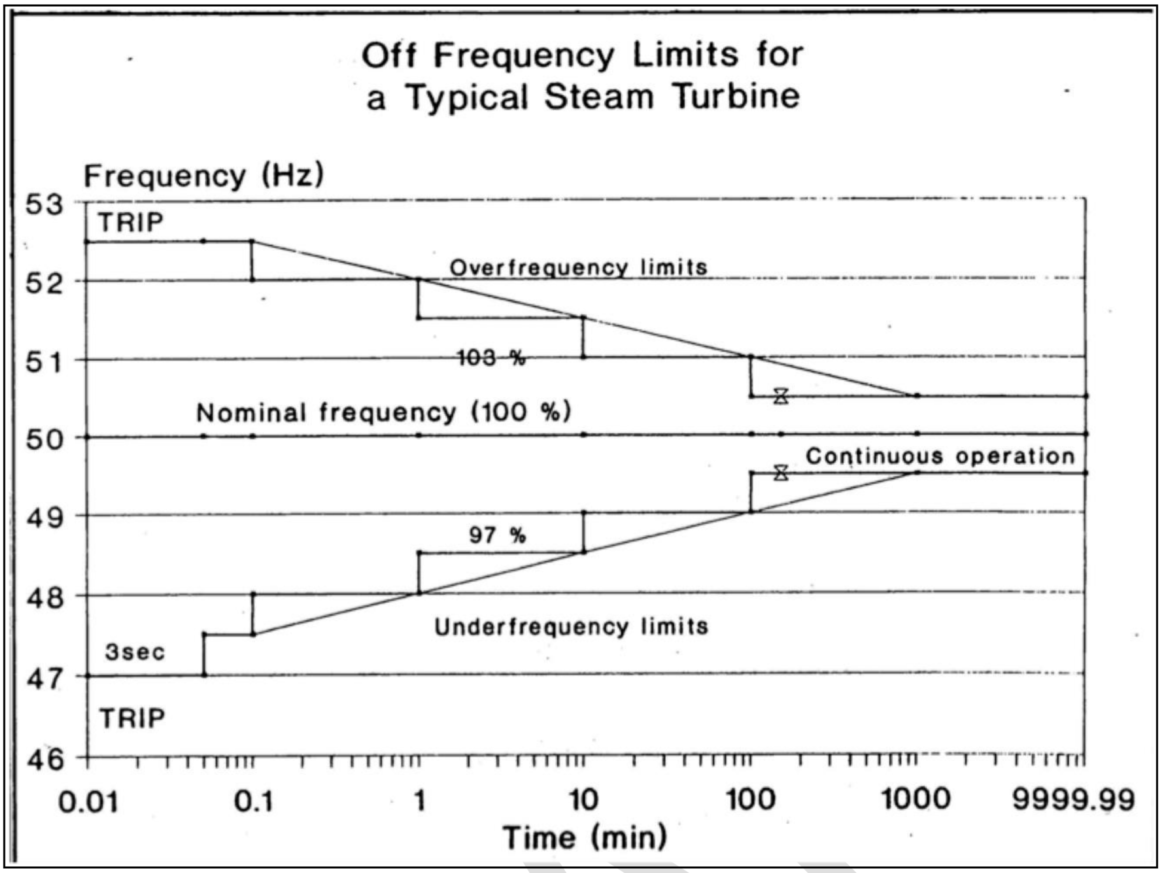


Figure 6: Off Frequency Limits for a Typical Steam Turbine

While the generator protection systems are designed to protect the machines from immediate damage that would result from operation outside frequency limits, other mechanisms are required to ensure the long-term operation of generating machines. As the stresses caused by off frequency operation build up over time, the time that machines operate outside the normal operating range needs to be managed. This is achieved through the application of frequency control criteria. Off frequency limits for a typical steam turbine are shown in Figure 6.

6.2 Transmission System Voltage

6.2.1 Overview of Technical Requirements

Voltage levels for the electricity network are declared to:

- provide the basis on which to build secure and stable network operations and planning.
- enable users to connect appropriately designed and rated equipment to the network.

To ensure that the network will remain stable, and that equipment will operate as designed and without damage, system voltage must be maintained within specified limits.

Step changes in voltage can interrupt sensitive processes and equipment and therefore limits are placed upon the size of voltage step changes that result from frequent or infrequent switching of network elements, loads and generators.

Voltage is managed through the provision of sufficient real and reactive power to meet the load demands, given the network topography. Real power can only be provided through generation. The flow of reactive power to control voltage can be managed using synchronous generators, transformer tap positioning, voltage regulating devices, capacitor and reactor banks, SVCs and Statcoms.

Clause 2.2.2 of the Technical Rules defines the applicable performance requirements for both the transmission system and distribution system:

- the relevant voltage performance assessment timeframes, including transient and subsequent phases.
- pre and post event system steady state voltage limits;
- the allowable step-change in voltage resulting from switching operations; and
- allowable transient under- and over-voltages and applicable time periods.

Clause 2.3.7 requires the Network Service Provider to monitor power system performance (and implicitly plan network development and augmentation) to ensure compliance with voltage requirements. It also provides the minimum measurement requirements in response to a complaint regarding voltage magnitude.

Flicker

Flicker in power systems relates to the effect of varying voltage levels on the output of electrical equipment (particularly lighting equipment). It is similar to voltage step change in that it is caused by the same actions (switching of network components, loads and generators). The difference between flicker and step-change is that flicker relates to the accumulation of step changes over time, whereas step change is measured as a single event. Flicker is usually caused by equipment or processes that involve many and frequent changes in load characteristics.

While flicker can affect sensitive processes and equipment, the main concern in relation to flicker is the visual impact of variations in incandescent light output on people.

Voltage flicker is considered during connection studies in relation to new loads and generators. It may also be an issue where a network augmentation alters the connection between an existing disturbing (flicker causing) load and other customers.

Flicker is not generally studied for all new connections, but studies are completed where a new connection contains equipment that is known to be a disturbing load or other plant type[12]. Flicker studies will be performed to determine the emission limits applicable to a new user (load) connection, or whether a given generator meets the required performance standard limits. The limits need to be discussed with the customer and it is customer's responsibility to ensure that they comply with the limits provided by Western Power (as per Technical Rules clause 3.2.1.(b)). Compliance is monitored following commissioning using either temporary or permanently installed monitoring equipment. It is usual that permanent disturbance recorders are required for large wind farms.

The Technical Rules are based upon the requirements of the Australian Standard AS/NZS 61000.3.7 (2001) on electromagnetic compatibility, part 3.7: Limits -Assessment of emission limits for fluctuating loads in MV and HV power systems.

[12] Disturbing types of plant and equipment including variable speed drives, arc furnaces, welding equipment and some types of generator plant.

The Technical Rules contains the following clauses in relation to flicker:

- Clause 2.2.4 – outlines the applicable limits on flicker levels within the transmission and distribution network;
- Clause 2.3.1 – provides guidance to the Network Service Provider on the management and allocation of limits to Users;
- Clause 2.3.7 – provides minimum measurement requirements that need to be taken in response to a complaint regarding flicker.

Harmonics

Harmonics currents and voltages within the power system are a quality of supply issue. Harmonics currents cause distortion to the voltage waveform and can be reflected through the entire network. Harmonic resonance can result in amplification of some harmonic frequencies in parts of the network.

The adverse impacts of voltage waveform distortion caused by harmonics are wide ranging - impacting loads, generation, network supply equipment, protection systems and communications equipment.

To ensure reliable operation of the network and prevent damage to plant, overall limits are imposed on levels of harmonic voltage distortion within the network and also according to the "order" of the harmonic with respect to the fundamental power system frequency of 50 Hz.

The Technical Rules contain the following criteria in relation to harmonic voltages:

- Clause 2.2.5 – imposes limits to harmonic voltage content levels in different parts of the network (transmission and distribution). There is an allowance for slightly greater content at the distribution level, in recognition that the contributions at this level are more difficult to determine and that the risk of propagation through the network is lower.
- Clause 2.3.2 – provides guidance to the Network Service Provider on management and allocation of limits to Users.
- Clause 2.3.7 – provides minimum measurement requirements that need to be taken in response to a complaint regarding harmonic voltage distortion.

Negative Phase Sequence

Voltage unbalance is a quality of supply issue that can lead to damage to equipment through overheating of three phase motors, harmonic current generation and excessive power loss.

Voltage unbalance within a three phase power system can be detected through the measurement of negative phase sequence voltage.

The Technical Rules contain the following clauses in relation to voltage unbalance:

- Clause 2.2.6 – imposes limits on voltage unbalance levels within the transmission and distribution network;
- Clause 2.3.3 – requires the Network Service Provider rectify any unbalance caused by its own systems or require a User to rectify any unbalance caused within an installation;
- Clause 2.3.7 – provides minimum measurement requirements that need to be taken in response to a complaint regarding voltage unbalance.

6.2.2 Network Planning Considerations

Network voltage is a fundamental aspect of transmission system studies. The performance of the network under normal operating conditions; during and after routine switching operations; and after outages (planned and unplanned) is relevant.

The Technical Rules specify an acceptable range for voltages during normal operation, together with allowable step-changes for routine and infrequent switching. Switching can include the connection/disconnection of network equipment such as transmission lines, capacitor banks or transformers or user equipment such as loads or generators.

Planning studies need to be undertaken with due consideration to the network topography, load characteristics, generator responses and automatic control systems to ensure that study results reflect actual system responses.

Some users may have sensitive equipment installed where poor voltage control could lead to equipment damage or interruption to processes, which could be costly. In such circumstances, the Technical Rules provide flexibility to negotiate for more onerous voltage limits to be applied. In such circumstances it would be normal for the party requiring more onerous limits to responsible for any additional associated costs.

Network Design

Under normal conditions, the transmission network (66 kV and above) must operate within ±10% of the nominal voltage. The transmission network is a complex, meshed network. Network complexity requires that for the most part, voltage is controlled manually by Western Power as (Network Service Provider) and procedures are in place for managing voltage control. As the network becomes more complex there are more automatic voltage control systems in place (such as Statcoms, synchronous compensators and SVCs). These devices are also operated by the Network Service Provider according to procedures.

Voltage control is achieved through the generation of reactive power, switching of capacitor/reactor banks and tap changing of transformers at terminal stations and power stations. Planning studies need to be undertaken with reference to Western Power (as Network Service Provider) and AEMO voltage control procedures to ensure that the network studies are reflective of how the system would be operated during normal and/or emergency conditions.

The distribution voltage limits are within a narrower margin for normal operating conditions, but these are relaxed in emergency situations. Distribution voltages are heavily reliant upon transmission network voltages and for this reason it is essential to maintain strict limits at the transmission level. It should be noted that in some instances it may be necessary to restrict the transmission network voltage to a band tighter than ±10% of the nominal voltage in order to ensure that the distribution voltage attains its set point following tap changing.

The distribution system is a radial network and the use of automatic voltage regulation systems is possible. Distribution voltages are controlled through automatic voltage regulation by transformer tap changing at zone substations and voltage regulators along distribution feeders, or by switching of capacitor banks (usually time switched within substations and voltage controlled along feeders).

The connection of generation at the distribution level can impact on the correct operation of automatic voltage control facilities. The primary issues that are likely to arise through connection of generators to the distribution network are corruption of line drop compensation (LDC) used with transformer AVRs (altered load flow patterns through the transformer affect the LDC applied) and local voltage rise issues close to the generator connection point.

In planning studies voltage needs to be checked for normal operation, following equipment switching and following outages of plant or network components. Voltage is always checked during high load scenarios but in some circumstances low load and shoulder load scenarios are also of importance.

For lightly loaded systems with high capacitive charging (such as rural networks) over-voltage at low load is a critical consideration.

For parts of the network that are closely connected to intermittent power generation (e.g., near peaking power plants) it is necessary to consider a range of generation and loading scenarios when conducting voltage studies.

When assessing voltage step-change, it is usual to consider the system operating in its normal state.

Maintaining system voltages within respective limits, including step-change criteria, is an explicit requirement within the wider network planning criteria, which also applies to the design of demand and generation connections. Section 4 of this Guideline provides further details of the specific requirements, in broad terms there must be no unacceptable voltage conditions arising on the power system following considered contingency events affecting generation and demand connections plus the wider substation system and MITS.

In practical terms, it would be difficult to justify a network augmentation on the basis of failing to meet the step-change criteria alone. However, consideration of step-change criteria would be an integral aspect of network and substation design for an augmentation justified on other grounds. Voltage step change is a consideration when a part of the rural transmission network is migrated from N-0 to N-1 e.g., once the group demand exceeds 10 MVA (for zone substation transformer contingencies) or 20 MVA (for transmission circuit contingencies).

Substation/Equipment Design

Aspects of substation and equipment design that affect step change are:

- transformer tap step size and range;
- use of larger conductors or line configurations to reduce network impedance;
- capacitor bank size/rating;
- the use of in-rush reactors or point-on-wave switching methods for connecting capacitor banks, long transmission lines and large transformers.

Due to the need for harmonic filtering reactors with capacitor banks, the most usual method for limiting voltage step change resulting from capacitor bank switching is the use of in-rush reactors. Point on wave switching schemes have been used in the past, and in some circumstances, they may be appropriate to reduce voltage rise on switching of devices.

Flicker

Flicker can be mitigated through good design of the plant installations, but there may be instances where network augmentation needs to be considered to achieve suitable outcomes.

Within installations, the use of controlled (soft) starting systems for motors and generators, in-rush reactors, better load balancing and higher voltage connections can aid in reducing the flicker seen in the network.

When these mechanisms are insufficient to meet requirements, or are prohibitively expensive, network solutions need to be considered. As flicker is related to voltage drop and voltage drop is caused by power flow through the network, network based solutions are based around the following methods:

- Reducing network impedance at the point of connection;
- Increasing the network impedance between the disturbing load and other loads; and/or
- Managing power flow through the network, notably reactive power.

The impedance of the network can be reduced by either connecting at higher voltage, using larger conductors, creating additional network paths, or using larger power transformers.

Disturbing loads can be separated from other loads by using dedicated transmission lines (or feeders depending on connection voltage) or by using dedicated transformers.

Reactive power flow through the network can be managed using reactive compensation - series or shunt capacitor banks, SVCs or Statcoms.

Harmonics

Power system harmonics are considered during connection studies in relation to new loads and generators (particularly those using power electronics which are a known source of harmonics).

From the network perspective, harmonics may be an issue when connecting new reactive compensating devices. Capacitors and reactors can alter the “harmonic impedance” of the network (and therefore the transmission of harmonics through the network), while the switching controls for devices such as SVCs can actually generate harmonics. Changes in network topography may result in changes to the background levels of harmonics experienced within the network.

Where a new connection contains equipment that is a known source of harmonics, the requirements need to be discussed with the customer. Western Power will provide emission limits specific to the connection and measurements taken following commissioning to ensure compliance with regulatory requirements.

Where an installation is the primary source of power system harmonics, mitigation should be undertaken within the installation. This may be achieved through specification of low harmonic emissions for equipment or installation of filtering or compensating devices.

Where there is no identifiable source of harmonics, mitigation needs to be undertaken at the network level. This may be achieved through a variety of measures including use of series reactors in capacitor bank circuits, transformer winding design or filter banks.

Negative Phase Sequence

Voltage unbalance is caused by uneven loading of each of the phases within the three phase network. The uneven phase loading can result from either poor network design (and operation) or from loads within customer installations. It is necessary to identify the source to rectify a problem.

Network induced unbalance can occur through either poor distribution of single phase loads or through asymmetrical transmission line impedances. Both of these factors can be managed by prudent planning.

Uneven phase loading at the transmission level is most commonly associated with line design, although there are some large two phase loads on the network (railway loads). Voltage unbalance due to asymmetry of transmission lines can be reduced by transposition of conductors along long transmission lines. Special studies may be required to identify the optimal conductor transpositions at various line loadings.

Transpositions made at terminal stations or substations are preferable due to substantially reduced costs. All new transmission lines should be designed such that they do not cause a negative phase sequence component of voltage greater than 0.3%.

It is Western Power's interpretation that negative phase sequence limits specified in the Technical Rules are intended to apply during normal operating conditions. They are not intended to apply during faults, single pole interruptions, line switching, transformer energisation, shunt capacitor bank energisation or shunt reactor energisation within the transmission network.

Although not yet incorporated in the Technical Rules, unbalance limits are currently allocated to network users in accordance with IEC/TR 61000.3.13 (2008) - Electromagnetic compatibility (EMC) - Part 3-13: Limits - Assessment of emission limits for the connection of unbalanced installations to MV, HV and EHV power systems - Including Corrigendum 1. This standard is current in working draft development stage by Australian Standards.

6.2.3 Supporting Material

Harmonics

Harmonic sources include:

- switching forms of control based on power thyristors as used in:
  - arcing load such as those of arc furnaces
  - thyristor-controlled reactive-power compensators (e.g., SVCs or Statcoms)
  - thyristor-controlled series capacitors
  - frequency converter (i.e., cycloconverter being also a source of non-integer harmonics also known as interharmonics)
  - HVDC converter stations
  - high-power ac/dc conversion for the supply of loads such as those of smelters
  - thyristor-controlled motor load
  - other industrial and domestic loads including thyristors.
- harmonics in the magnetising current of transformers, particularly the third harmonic, due to the non-linear form of transformer magnetisation characteristics
- waveform distortion in rotating machines in transient periods immediately subsequent to disturbances to steady operating conditions
- variations in air-gap reluctance which set up a continuous variation in flux which in turn distorts wave shapes
- flux distortion in synchronous machines arising from pulsations and oscillations in the field flux caused in turn by movement of the poles in front of the projecting armature teeth

The adverse effects of harmonics in power systems can be widespread:

- Thermal stressing in rotating machines and transformers
- Overloading of shunt capacitor banks
- Interference with:
  - power line carrier communications systems

  - telecommunication facilities (network based and public systems)
  - protection systems
  - the firing sequence in thyristor controllers
- possible resonances at harmonic frequencies
- errors in metering and instrumentation
- malfunction of computer equipment
- rotating machine vibration

Individual non-integer (fractional) harmonics should be included in the distortion limits by incorporation into the nearest even harmonic limit.

6.3 System Voltage and Generator Stability

6.3.1 Overview of Requirements

Transient Stability

The transient rotor angle stability criterion is fundamental to maintaining overall power system stability. Transient rotor angle stability defines the ability of synchronous machines within the power system to return to a stable, synchronous state following a major system disturbance. A major disturbance is usually considered to be a three-phase fault, loss of generation or loss of a large load.

During and following a system disturbance, generators will be affected by the changes in power demand placed upon them. Usually, generators located close to the disturbance, or highly responsive (low inertia) generators will be the most affected by a disturbance. The fluctuating power demands (swings) will cause the affected generators to speed up or slow down with respect to the remainder of the generators within the system. If these swings are able to be reduced to a level such that the units remain in synchronism with the system, then the system is referred to as stable. If these generators continue to vary their output and operating angle with respect to the remainder of the system, then they are unstable, at risk of failing or being removed from the system to protect themselves and therefore the system is at risk through loss of generation.

The Technical Rules contains the following clauses in relation to transient rotor angle stability:

- Clause 2.2.8 – requires that the power system must be planned such that following a credible fault event the performance requirements of any generating system, with respect to transient stability, are not exceeded;
- Clause 2.3.5.2 – defines obligations on the Network Service Provider in relation to power system stability and modelling requirements.

Oscillatory Stability

Oscillatory stability refers to the stability of the individual generators that comprise the power system, with respect to each other and the system as a whole. Following every system disturbance (large or small), there will be some rotor angle swing as the generators within the system settle at a new operating point. These swings should reduce (damp) over time. The rotor angle stability criteria set out the acceptable range for damping time for rotor angle oscillations.

Oscillatory stability may be affected by large system disturbances (as for transient stability) or by small disturbances that cause sets of machines in different parts of the network to “swing” against each other.

The Technical Rules contains the following clauses in relation to oscillatory rotor angle stability:

- Clause 2.2.9 – defines the damping ratio required for electro-mechanical oscillations;
- Clause 2.3.5.2 – defines obligations on the Network Service Provider in relation to power system stability and modelling requirements.

Voltage Stability

Voltage stability refers to the ability of the power system to maintain voltage control during normal operations and to restore voltage to a stable and satisfactory level following a disturbance. Short-term voltage stability usually deals with the power system voltage response during and immediately following a system disturbance. It is essential that equipment can withstand short excursions in power system voltage to ensure safety, prevent damage to equipment and to ensure the overall stability of the power system (equipment failure resulting from an overvoltage event could lead to further outages, leading to higher stresses on parts of the system). Short-term voltage stability is usually assessed using dynamic power system studies. Long-term voltage stability usually deals with the power system voltage response over tens of seconds to minutes and even hours, either following a system disturbance or under stressed conditions such as high loading and limited generation availability.

Voltage instability can lead to voltage collapse in parts of the network that can very quickly spread throughout the network – leading to complete loss of the system. Reactive power support can mitigate underlying voltage stability issues.

The Technical Rules contains the following clauses in relation to short term voltage stability:

- Clause 2.2.10 – describes voltage stability considerations and requirements within the Technical Rules;
- Clause 2.3.5.2 – defines obligations on the Network Service Provider in relation to power system stability and modelling requirements.

6.3.2 Planning Application

Transient Stability

Transient stability is of particular interest during studies contemplating the connection of new generators, or substantial developments (network augmentation or the connection of large loads) in remote parts of the network.

The Technical Rules require generators with a total rated output of 5 MVA or more remain in synchronism following a credible contingency event.

For planning applications this is taken to mean any unit rated at 5 MVA or above, regardless of DSOC (Declared Sent Out Capacity) of the unit. DSOC is the capacity that may be transferred through the network. A unit may have a higher rating than DSOC if it is supplying load internal to the customer premises.

Transient stability is the ability of a power system to maintain/retain system synchronism when subjected to a severe disturbance. It is assessed by monitoring the relative rotor angle between one (or a group of) synchronous machines and the rest of the system. If this angle reaches (or exceeds) 180 deg. without returning, a ‘pole slip’ and loss of synchronism are deemed to have occurred. Generators connected to remote parts of the network, via long transmission lines or generators with low total inertia (e.g., diesel or aero-derivative) are most vulnerable to instability. Fast clearance of faults is one means of managing generators that may be susceptible to instability.

When undertaking transient stability studies, it is essential that the most severe disturbance is identified for the particular operating conditions. The system load and generation schedule, and the particular outages will have a bearing on the most severe disturbance for different parts of the network. As the network develops, the load/generation patterns and outage conditions will almost certainly alter and therefore periodic checks are required to identify the most severe conditions.

Disturbances may include three phase faults, loss of generation, loss of a large load or other failure.

When undertaking planning studies in relation to transient stability, the initial conditions and considerations are vital to producing relevant results. These conditions and considerations include:

- Loading conditions – locally and network-wide, including voltage dependent load behaviours;
- Generator scheduling;
- Protection modelling (tripping times);
- Generator modelling (including generator control systems such as AVR and system stabilisers); and
- System modelling.

Depending on the situation, a number of scenarios may need to be considered. It is important to note while the Technical Rules require that criteria be met for any generation and load condition, to do so would generally result in undue costs or restrictions placed on new generators. For this reason, only credible load/generation conditions should be considered.

Due to the complex nature of stability studies, not all possible outages can be studied and the appropriate outages for consideration will need to be identified. A degree of prior knowledge in relation to the network performance and susceptibilities will assist in identifying conditions of interest. However, it will be essential that the system is continually reassessed as the network develops.

Transient stability is based on the relative rotor angle swing between two synchronous machines (or groups of machines). Relative rotor angle swings in excess of 90 degrees may lead to the situation where the rotor angle does not return and the angle increases to 180 degrees and beyond (where 'pole slip' or synchronous instability occurs).

In indicative planning studies, an initial generator relative rotor angle swing angle of less than 120 deg. is considered stable, whereas a swing of 120 deg. or more with subsequent swings of lower magnitude would be considered an indicator of instability, requiring more detailed study. Relative rotor angle swings exceeding 120 deg. usually only have a small margin before pole slipping occurs.

For detailed studies, a pole slip is deemed to have occurred if the post-disturbance rotor angle exceeds 180 deg.

Some of the factors influencing transient stability are:

- impedance between generation sources – higher impedance makes the link between generators weaker and the generators therefore more prone to instability;
- generator reactance – lower reactance reduces the initial rotor angle and therefore the magnitude of the initial swing following a disturbance;
- inertia of the generating unit – higher inertia produces a slower rate of change in rotor angle and therefore enhances stability;
- fault clearance time – faster clearance results in a shorter disturbance time and therefore lower rotor angle swings.

When transient stability issues are identified, there are several paths for resolution – some may be relatively moderate in cost while others will be substantial. If the issue, or susceptibility is identified prior to generators being installed/connected then there may be some scope to modify the generator characteristics to provide a more stable machine.

Historically, improving protection clearance times has been a low cost solution, however, this means that many protections are now operating very fast and there is little scope to use this as a solution in the future. Other alternatives, such as braking resistors, may also be reasonably low cost.

Oscillatory Stability

While oscillatory rotor angle stability is generally studied in relation to the connection of new generating plant to the network, it is also of consideration for remote parts of the transmission network that contain generating plant. It is related to the way in which groups of generators and their control systems interact with each other.

Oscillatory rotor angle stability is affected by the way in which the automatic voltage control systems of generators respond to small or large changes in the power system. As each generator has slightly different characteristics and control mechanisms and will be differently affected by each and every change in the power system, the time and magnitude of each generator's response will differ. In some cases, generators will over-respond while others will under-respond. Following each disturbance, it will take time for all machines to find a new steady-state operating point.

Oscillatory stability is measured by the time taken to return to steady state operations – this is termed the damping ratio. If oscillations cannot be reduced, they may start to increase, resulting in risk to the overall system.

The Technical Rules require that oscillatory rotor angle stability limits are met for the contingency and equipment maintenance conditions e.g., N-0, N-1 or N-1-1, etc appropriate for that part of the network as defined under the Planning Criteria – see Section 2.5 of the Technical Rules. Oscillatory stability studies are to be conducted for the worst credible load and generation schedule and for the most severe credible contingency as defined in the Planning Criteria with respect to demand and generation connections and the wider MITS. Protection tripping times are to be based on the slowest protection scheme (either the slowest of the two protection schemes or if there is only one scheme, the back-up scheme) applicable to the network area and voltage being studied.

There are a number of types of oscillation modes that may arise within a power system:

- Inter-generator oscillations – occur between two or more generators located within a power station or located very near to each other;
- Inter-area oscillations – a group of generators in one part of the network oscillate against a group of generators in a different part of the network (the network interconnected with a weak tie); and
- Local-mode oscillations – one or a group of generators in a power station or located very near to each other oscillate with respect to the remainder of the system.
- Electromechanical oscillations will occur in power systems as a result of both everyday operations (such as load changes or minor switching events) and major disturbances (such as faults). The transient stability of generators is assisted by the use of fast acting control devices (excitation systems), but the operation of these may result in ongoing small oscillations. These oscillations need to be controlled (and damped) to ensure oscillatory stability is achieved. Oscillatory stability often relies on the use of power system stabilisers.

When undertaking planning studies in relation to oscillatory stability, the initial conditions are vital to producing relevant results, as are the disturbances to be considered (small and large) and the response of all machines connected to the network. Similar to transient stability studies – load characteristic and generator scheduling is an important first step in system modelling. It is vitally important to accurately represent generator characteristics, control systems and system stabilisers to adequately study oscillatory stability. This may need to be verified with field testing of generator responses to changing conditions.

If power system simulation studies indicate the possibility of insufficient damping, then a generator must introduce appropriate measures at the planning and design stage to prevent the problem.

Generators subject to the WEM Rules may be required to include power system stabilisers in their installation – this requirement is covered under both the Ideal and Minimum Generator Performance Standard requirements see WEM Rules A12.4.2.2 and A12.4.3.2.

Voltage Stability – Short Term

Short term voltage stability is related to the ability of generating plant to respond to system disturbances to support the network in "riding-through" fault conditions and then to provide sufficient reactive power to aid the system in recovering to adequate voltage levels to maintain system security without load shedding.

Short term voltage stability is primarily studied in relation to the connection of new, large loads or new generators to the network. It is also relevant where generators or their control systems are modified, or where there are network augmentations to remote parts of the network.

The Technical Rules require that the power system survives an initial disturbance and reaches a satisfactory new steady state; and that stable voltage control is maintained following the most severe credible contingency event.

This requirement is taken to mean that the power system is able to continue to operate through a fault, and following clearance of the fault, voltage recovers to a stable point and that this point is controllable. Once a stable operating point is reached, there may need to be subsequent action by Western Power (manual or automatic) such as tap-changing and network switching, plus AEMO rescheduling of generation, to ensure that the power system is in a secure state ready to manage any subsequent disturbances. Note though that should any subsequent disturbance take the network beyond the contingency criteria appropriate for that part of the network e.g., demand connection criteria (N-0, N-1, or N-1-1), generation connection criteria or MITS criteria, the power system may not meet the Technical Rules.

Under-voltage load shedding (UVLS) schemes may be employed to aid system security in the event of system operating conditions outside the contingency criteria of the Technical Rules.

Short term voltage stability is primarily related to the dynamic response of load (such as induction motors) and of reactive sources such as generators, SVCs and Statcoms to disturbances. Therefore, it is essential to use dynamic (time-step) simulations rather than steady-state type simulations, although there is value in performing initial steady state assessments that consider tap-changers locked, loads modelled with appropriate voltage dependent load models and the ability of the system to land in a satisfactory operating state i.e. voltage in the range 0.9 – 1.1 p.u.; 0.9 p.u. is considered the minimum acceptable steady state voltage pre- and post-transformer tap changing. To adequately study short term voltage stability detailed system and plant models are required.

Voltage stability is affected not only by generator responses, but also by load responses to varying voltage levels. During low voltage events, some loads (such as induction motors) may stall. This leads to excessive reactive current draw, further exacerbating the low voltage condition. Other loads (purely resistive loads such as incandescent lights and heating) have "self-healing" properties and will reduce their apparent load at low voltages, thereby assisting voltage recovery. Therefore, accurate load representation is important in achieving realistic results when studying short term voltage stability.

It is also essential to include in the models:

- any generator (or other reactive source) under- or over-excitation limiters (UEL or OEL);
- under-voltage load shed (UVLS) schemes that will operate during the study time are included in the system model.

Noting that UVLS schemes should only be employed during system operating conditions that fall outside the contingency criteria for that part of the network, as defined in the Section 2.5 Transmission System Planning Criteria in the Technical Rules.

The Technical Rules does not specify an absolute time for voltage recovery. As the system was deemed to comply at the time the Technical Rules were first approved, the general methodology to assess satisfactory short term voltage stability has been to observe whether:

- the system recovers to a stable voltage of at least 0.9 p.u. Note that the short-term voltage is considered to reach its final level when the voltage level remains almost constant for several seconds after a system disturbance;
- the overvoltage requirements of clause 2.2.10 of the Technical Rules are met; and
- a new connection does not cause any adverse impact(s) to existing users e.g., disconnection or reduction in power transfer capacity.

Where issues are identified with regard to short-term voltage stability, a number of alternative solutions can be considered. These include:

- modifications to protection systems e.g., faster tripping times will aid faster voltage recovery;
- modifications to generator AVR systems;
- provision of greater voltage support capability by generators e.g., higher VAr capability;
- provision of local or remote dynamic reactive support, such as by Statcoms, SVCs, or other generators; and/or
- network augmentation (usually considered as a last resort due to cost).

Voltage Stability – Long Term

Long term voltage stability of the network relates to the time subsequent to an initial disturbance i.e., once the fault is cleared and the system is working towards a stable operating point. It relates to the time period immediately following that considered under short-term voltage stability, although there is generally some overlap between the two as voltage recovery is dependent on both fast acting and slower acting responses. Study is usually completed using steady-state type system models, but if more refined results are required then dynamic studies may also be used. The results of dynamic studies would generally be considered more accurate than steady-state simulations, but this is dependent on the appropriateness of the modelling used for loads, generators and their controllers.

The Technical Rules require that the network must demonstrate a positive reactive power margin – meaning that reactive power reserve indicated by the QV curves determined through the studies must be above 0 MVAr. This margin is required both prior to and following tap changing operations. The reactive power reserve at a point in the network is the amount of additional reactive power that could be supplied from that point and maintain voltages within the prescribed limits specified in clause 2.2.2(a) of the Technical Rules.

The Technical Rules provide a very prescriptive method for assessing long term voltage stability. The appropriateness of this should be reviewed and perhaps modified, as the considerations to be made will change over time as the network develops. Any optimisations should be proposed as a rule change.

The methodology specified in the Technical Rules originates from the WSCC (Western Systems Coordinating Council of USA) guidelines which were developed as a practical means of studying long term voltage stability in networks, following a number of voltage collapse situations that occurred in that system. The methodology is based on developing QV (reactive power – voltage) curves for the network in a number of operating states. These are intended to identify the most susceptible areas for voltage collapse, and the most critical events that could lead to a voltage collapse situation developing.

The initial conditions for the studies specified in the Technical Rules were based on the WSCC methodology, adapted for the SWIS, after consideration of potential operating conditions, historical plant performance and integrity of modelling information. The conditions include an increase in power transfer across the network of 5%. This margin is intended to account for any errors in load forecasting or network modelling. Refer to Section 6.3.3 of this Guideline (below) regarding application of the 5% power transfer margin to the system model.

As noted above, the system is considered stable if a positive reactive power margin is demonstrated i.e., reactive power reserve is >0 MVAr. Other jurisdictions require a margin to be demonstrated i.e., an error margin is built into the reactive power reserve – either in terms of absolute MVAr or in MVAr related in percentage terms to the system fault level. The 5% power transfer increase is an alternative means of providing such a margin.

For the study case set-up, the initial conditions are intended to replicate a credible scenario. Although voltage collapse situations are often associated with heavily loaded systems, in studying the SWIS many instances have been found where the system is more susceptible to voltage collapse during times of reasonably high shoulder-load rather than peak load. This is often due to these periods being used for plant maintenance (both transmission plant, substation plant and generating plant). It is also during these times that high cost generating plant located near the load centre is not being utilised and therefore the reactive power support usually provided by these plant during high load times is not available.

Load outages are also important considerations, along with generation and plant outages, as these can affect the power flows through the network and lower demand may affect the amount of reactive power available from generators (a key determiner for voltage stability). As an example, the SWIS has been close to voltage collapse following a load shedding event where the load shed was located remote from the load centre and near major generation sources - this resulted in higher power transfer across a stressed network taking the voltages at the load centre lower.

For studies relating to the metropolitan area, the Technical Rules note that in addition to a general 3% unavailability of capacitor banks across the region, the reactive device that has the largest impact on the power system must be assumed to be out of service. This device may be a large capacitor bank, a generating unit, an SVC or a generator operated as a synchronous compensator. A number of test cases may need to be run to determine the appropriate device.

Long term voltage stability should be achieved with the system operating in the most onerous state according to the contingency criteria appropriate for that part of the network e.g., demand connection criteria (N-0, N-1 or N-1-1), generation connection criteria or MITS criteria. Identifying the most onerous operating condition will require a degree of study. While the N-1-1 operating condition may appear more onerous, the fact that generation may be rescheduled following the first outage, to cater for a subsequent outage, may make this scenario less onerous than an N-1 contingency.

Where issues are identified with regard to long term voltage stability, a number of alternative solutions can be considered. The most common are related to modifying the way in which reactive power is transferred across (or lost through) the network, as this is the most significant factor governing long term voltage stability. These include:

- reactive support through the use of capacitor banks near highly reactive loads;
- reducing reactive losses in the network through lower impedance transformers, installing additional transformers to reduce loading of transformers or using series capacitors in long transmission lines;
- provision of greater voltage support capability by generators (with higher MVAr capability);
- provision of local or dynamic reactive support such as by Statcoms, SVCs, or other generators; and/or
- network augmentation to reduce transmission line loading both prior to and following faults (usually considered as a last resort due to cost).

Not all network augmentation will be costly. Sometimes simple solutions such as providing additional switching points along long transmission lines will provide effective solutions to long term voltage stability issues.

Western Power has implemented a number of under-voltage load shedding (UVLS) schemes throughout the network to act as a last resort in prevention of voltage collapse. These schemes are not intended to be triggered by foreseeable contingency events, but rather to act in defence of the system in the event of a major system catastrophe that would otherwise lead to overall voltage collapse. There are a number of regionally based schemes protecting remote parts of the network, as well as a major scheme protecting the bulk transmission network supplying major load centres around the Perth metropolitan area

Temporary Over-Voltages

Due to customer concerns regarding the lack of suitably rated equipment, Western Power uses the curve shown in Figure 7 (a repeat of Figure 2-2 from the Technical Rules) to assess transmission network over-voltages.

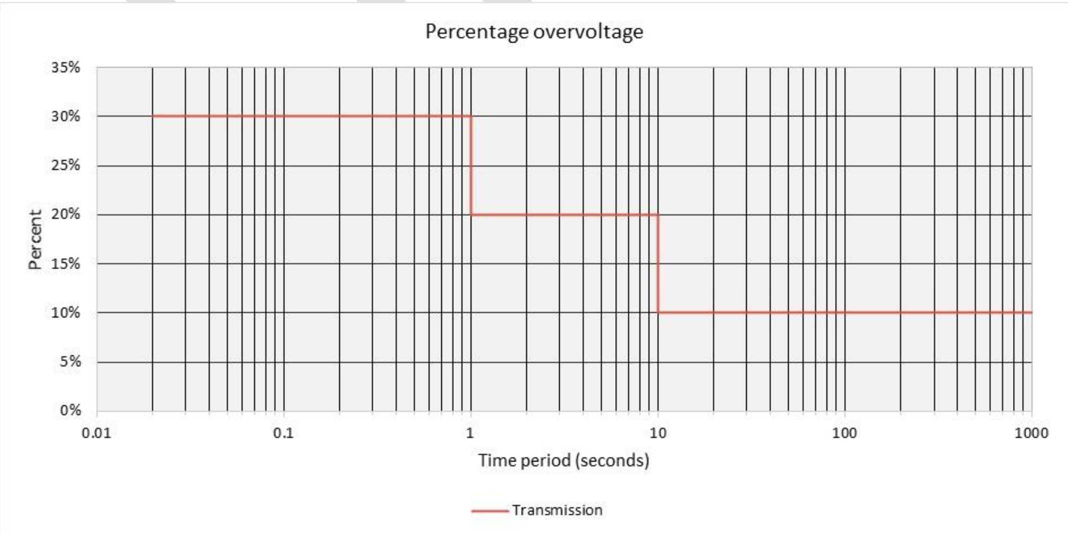


Figure 7: Transmission Network Overvoltage Curve used by Western Power

Where potential over-voltages above the curve limits may occur, mitigating schemes should be applied. These may include the use of reactive plant (reactors or capacitors) to control voltage during and after switching, or use of dynamic compensation such as Statcoms or SVCs.

To protect plant surge arresters or overvoltage protection schemes may be used.

The over-voltage curve shown in Figure 7 applies to the rms value of the voltage and is not intended to relate to electromagnetic transients. Studies to determine voltage levels and identify over-voltages will use load flow analysis and dynamic rms time based studies.

6.3.3 Supporting Material

Transient Stability

Transient rotor angle stability is the ability of individual generators to return to synchronism following a large disturbance.

During synchronous operation of a generator, the input mechanical torque is equivalent to the output electromagnetic torque of the machine. Any major disturbance to the power system will affect each of the generators on the power system – those closest to the disturbance will be most heavily affected. The potential effects of a disturbance are wide ranging, for example:

- a local fault taking the voltage at a generator's terminals to zero (or close to) would reduce the electrical power output of the generator to zero and result in the generator speeding up to absorb excess mechanical power input;
- loss of a large load substantially reducing system demand would have a similar impact; or
- loss of a large generator would necessitate additional electrical power output from generators and this would result in the generators slowing down.

In each of these scenarios above there would be a substantial mismatch between the input torque and power output of the generators affected by the disturbance. The generators would respond by slowing down or speeding up. Where the disturbance occurs in a relatively strong (interconnected) part of the system, all generators will share the burden, with only minor variation due to differing generator characteristics such as inertia. Where the disturbance occurs in a remote part of the system, the majority of the burden is borne by the generator/s closest to the disturbance. Depending on the situation, the remote generators may not be affected by the disturbance, or in a compounding effect may start to compensate for the power fluctuations near the disturbance by slowing down or speeding up, opposite to the originally affected plant. Where this occurs, the risk of instability is greatest.

Transient instability may cause the following detrimental effects on the system:

- pole slipping (due to low synchronising torque at voltages below 0.75 p.u.)
- tripping of unstable generators by pole slipping protection (loss of generation)
- system voltage collapse
- motor load loss and motor stalling on undervoltage
- electrical and mechanical stress on system and users' plant.

These impacts on a power system are generally not acceptable and need to be prevented.

The Technical Rules (clause 3.3.3.8 (a)) require all new generation units to be provided with pole slip protection. Pole slip protection is intended to remove an unstable generator from the system and prevent the disturbance from causing major problems to other users. Pole slip protection only removes the unstable generator from the system after it has slipped at least one pole, it does not prevent the initial pole slip.

Pole slipping protection is an avenue of last resort and should not be used instead of preventing the unstable situation arising in the first place. The operation of pole slip protection to remove a generator from the system following a disturbance could have a detrimental compounding effect on an already stressed system.

Long Term Voltage Stability

Assessment Methodology

Western Power (as *Network Service Provider)* must model the *power system* for long term stability assessment and transfer limit determination purposes, pursuant to clause 2.3.7.3(b) using the following procedure:

- for terminal *substations* in the Perth metropolitan area, 3% of the total installed *capacitor banks* plus the reactive device that has the largest impact on the *power system* must be assumed to be out of service; and
- for other areas of the *power system*, including radials:
  - the normal peak *power system generation* pattern, or other credible *generation* pattern determined by operational experience to be more critical, that provides the lowest level of *voltage* support to the area of interest must be assumed. Of the *generating units* normally in service in the area, the *generating unit* that has the largest impact on that area must be assumed to be out-of-service due to a breakdown or other maintenance requirements. If another *generating unit* is assigned as a back-up, that *generating unit* may be assumed to be brought into service to support the load area; and
  - the largest capacitor bank, or the reactive device that has the largest impact in the area, must be assumed to be out-of-service, where the area involves more than one substation.
- In all situations the Network Service Provider must follow the following additional modelling procedures:
  - all loads must be modelled as constant P & Q loads.
  - the load or power transfer to be used in the study must be assumed to be 5% higher than the expected system peak load, or 5% higher than the maximum expected power transfer into the area. (The 5% margin includes a safety margin for hot weather, data uncertainty and uncertainty in the simulation). The power system voltages must remain within normal limits with this high load or power transfer.
  - the analysis must demonstrate that a positive reactive power reserve margin is maintained at major load points, and that power system voltages remain within the normal operating range for this 5% higher load; and
  - power system conditions must be checked after the outage and both prior to, and following, tap changing of transformers.

5% Power Transfer Margin

As Western Power’s reactive reserve assessment determines that the system is considered stable if a positive reactive power margin is demonstrated i.e., reactive power reserve is >0 MVAr, there is no margin incorporated into the assessment.

Margin for error (in load modelling, system modelling, generator capability, etc) is incorporated through inclusion of a 5% margin on power transfer across the network.

To model this, the base network model should be set-up and solved for the reactive reserve studies. Once this is achieved, the load flow across the most critical portion of the network (i.e., the interconnection under study or the bulk transmission network in general) should be noted. For studies into the bulk transmission network, for the present network arrangement (2011), the power flow from the south-west generators towards the metropolitan area, across the major 330 kV transmission lines is relevant.

Load within the metropolitan area (and supplied by the south-west generators) should then be increased sufficiently so as to increase the power transfer across the 330 kV lines by 5%. Note that this will equate to a <u>5% generation increase but not a 5% load increase</u>, as network losses will also increase. Some minor adjustments to the solved case may then be required.

3% Unavailability of Capacitor Banks

The 3% general unavailability of capacitor banks across the metropolitan region requirement is sometimes perceived as overly conservative. The following points support the current requirement, but do not preclude review in the future:

- 3% was originally determined from research into unavailability rates during peak load times. Subsequent investigations were conducted with a view to decreasing this figure, but each found that actual outage rates were substantially higher.
- While other jurisdictions do not make this allowance, Western Power's forecasting and study methods are quite unique. Not many transmission bodies have the information to model load and reactive compensation separately at the distribution (22 kV and below) level, as Western Power does. The load models for most other transmission network cases probably already include a degree of small capacitor bank outages as they are seen as part of the load rather than separate devices.
- The 3% outage rate may be modelled by either scaling down capacitors across the region (easily automated), or by switching off individual capacitor banks (may be targeted to model a more onerous situation). Given that the most onerous reactive source outage is already included, scaling down across the region is considered sufficient.

6.4 Power Transfer Limits

6.4.1 Overview of Requirements

An interconnected power network is a complex system. Numerous factors will affect the ability of the system to remain stable, while transferring power from generation sources to loads. The constraining factors will not only vary between different parts of the network but will also vary depending on the operating regime and environmental conditions in place at any time.

To enable the system to be operated in a stable and secure manner, it is necessary for Western Power to provide guidance to AEMO or others to understand which factors are critical for the various network elements.

Clause 2.3.6 of the Technical Rules specifies requirements with regard to assignment of power transfer limits.

6.4.2 Planning Application

Power transfer limits may be determined by a number of factors. These will be related to angular stability, voltage stability or thermal ratings. The power transfer limit for a particular part of the network may vary, depending on the loading conditions, generation schedule and weather conditions at that particular time. It is not practical to provide this information for each network element for all conditions.

The Technical Rules specifies in Clause 2.3.6 that the Network Service Provider (Western Power) must determine power transfer limits for equipment forming part of the transmission and distribution system. The power transfer limits should be determined in accordance with clause

For this reason, power transfer limits are only calculated when required by users or AEMO.

The Technical Rules require that a margin be incorporated into power transfer limits, if the limit is stability of the WEM Rules and provided to AEMO.

6.4.3 Determination of power transfer Limits

Based on the requirements stated in WEM Rules clause 2.27A.11 Western Power must document in a WEM Procedure the processes to be followed and the matters to be considered when developing and updating limit advice, as well as the actual approach followed. This includes detailing how Western Power estimates thermal network limits. The reference WEM Procedure is available on WA Government website[13] and on Western Power's website[14].

6.5 Fault Currents

6.5.1 Overview of Requirements

Fault current criteria are specified to ensure that the network is designed and operated safely. All plant has a short circuit rating (either a withstand rating for standard plant or interrupting rating for switchgear).

Without fault rating criteria, the network fault levels may be subject to uncurtailed increase resulting in either inadequately rated plant and presenting a safety risk to personnel and the general public, or potentially excessive network augmentation costs in providing adequately rated plant.

Clauses 2.5.6 and 2.5.7 of the Technical Rules deal with fault currents for the transmission system. Note that there are no maximum fault current limits stated for the transmission system.

Applicable fault currents and limits for the distribution system are presented in clauses 2.6.4 and 2.6.5 of the Technical Rules. Specific maximum fault levels are provided for the distribution network for all voltage levels from LV (415 V), MV (6.6 kV) and HV / EHV (11 kV, 22 kV and 33 kV).

6.5.2 Planning Application

The Technical Rules require that the maximum calculated fault level at any point in the network does not exceed 95% of the rating of the equipment fault rating at that point. The Technical Rules also require that the maximum fault current at the connection point of a User be specified in the relevant connection agreement.

Given the continual development and changing nature of transmission and distribution systems, the maximum fault level at one point in time may easily be exceeded within a short space of time. For this

13 WEM Procedure Limit Advice requirements: **Error! Hyperlink reference not valid.**

14 Western Power's Limit advice requirement procedure Limit Advice Development (westernpower.com.au)

reason, the various parts of the transmission network have had maximum design fault ratings applied to them. Western Power designs its substations and transmission lines to meet these maximum fault levels (with some exceptions). Network augmentations and new generator connections consider fault level impacts and are designed to limit fault levels to within these design ratings. Design fault ratings were originally derived from assessment of network fault levels and projected increases, together with consideration of standard ratings of readily available plant.

Table 4: Design Fault Ratings

Operating Voltage (kV)	Fault Rating (kA)	Withstand time (sec)
330	50	1
220	25	1
132 (terminal stations)	50	1
132 (substations)	40	1
66	25	3
33	13.1	3
22	16	3
11	25	3

The lower voltage (<66 kV) fault ratings are based upon three standard transformers (12% impedance on 20 MVA) or two low impedance transformers (8% on 20 MVA) operating in parallel. For the urban networks, older transformers were specified with 8% on 20 MVA, and newer transformers are 12% on 20 MVA. The older country network transformers are of variable impedance, and newer transformers are 10.5% on 20 MVA.

Parallel transformer operation only occurs rarely during switching, as the distribution network is not normally rated to withstand these fault levels. However, as parallel transformer arrangements do occur from time to time for short periods e.g., when transferring load from one transformer to another, the substation plant is rated to adequately interrupt severe faults occurring during these times.

There are cases where it is very unlikely that design fault ratings would be approached e.g., remote and lightly loaded parts of the network. For these areas, a lower fault rating may be applied after due consideration of potential future network developments.

As stated in Clause 2.5.6 (and 2.6.4 for distribution) of the Technical Rules, the calculated maximum fault level must not exceed 95% of the equipment fault rating.

To make this assessment, fault levels must be calculated. Transmission network fault levels are calculated using load-flow software, using the following basic assumptions:

- All scheduled network generators are in service.
- All transmission plant normally in service, is in service.
- Embedded (non-market, non-scheduled) generators must be included in the model. Although these units do not contribute to the power transfer across the network, they will contribute to fault levels.
- Normally open network connections are treated as open.
- At substations where transformers are normally operated in parallel, this should be represented in the model.

- At substations where transformers are not normally operated in parallel, a range of scenarios should be considered, including where transformers may be operated in parallel. If there are operating conditions where fault rating breaches are identified, these should be advised to System Management. Depending on the situation, rectification may be required otherwise operating instructions employed.
- Fault levels are calculated following load flow, with voltages set according to standard operating practices and transformer automatic tap changing enabled.

The breaking capacity of circuit breakers is essential to ensure that faulted plant can be removed from the system quickly and safely. It is also a critical factor in ensuring network security. If a circuit breaker fails trying to interrupt a short circuit, it will require other circuit breakers to provide back-up protection. This will result in a greater portion of the network being affected by the fault.

The fault rating of plant is usually provided as nameplate ratings by manufacturers. These ratings are derived from the mechanical and thermal withstand properties of the plant.

The fault rating of conductors and cables is calculated. The rating is derived from the thermal response of the conductor to current flow.

Where fault ratings are thermally based, the time exposure to the flow of fault current is a critical factor in determining fault rating. The time exposure is directly related the maximum fault clearance time. There may be scope to increase the fault rating of plant by reducing the fault clearing time, but this will always be limited by the mechanical properties of the plant.

For 66 kV transmission plant, the maximum fault clearance time for determining fault rating is 3 seconds. For plant operating above 66 kV, the maximum fault clearance time is 1 second.

When assessing fault rating capability of plant, it is necessary to determine the actual contribution to a fault that is carried by plant, not just the total fault current at a busbar.