Subtransmission Network and Zone Substation Configuration

SDI 501

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Revision History

This standard replaces: SDI 501 am 1 – Transmission Network Configuration

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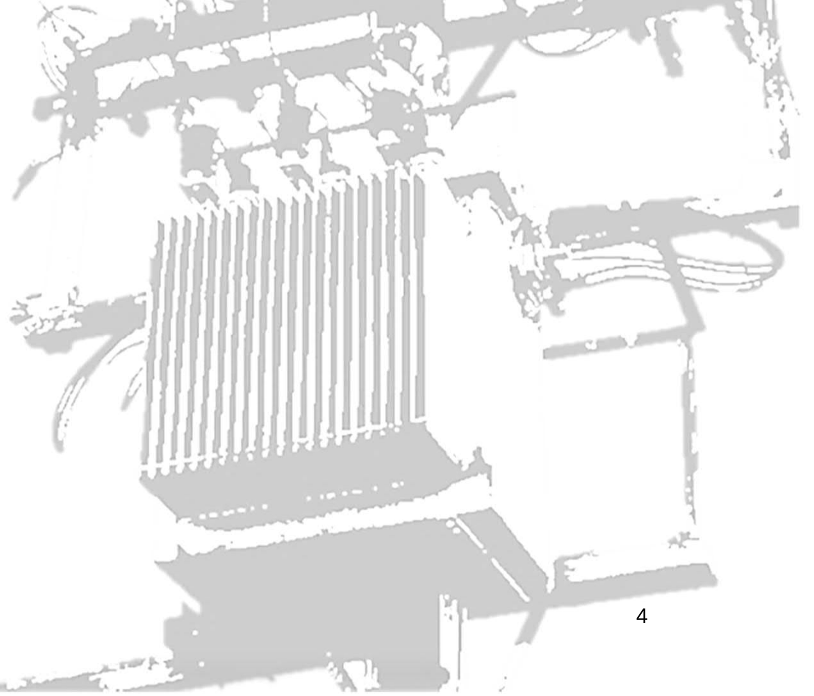


1 Scope

This standard sets out the network configuration parameters and objectives including physical, electrical and thermal properties of equipment in the Endeavour Energy sub-transmission network. It specifies equipment and network configurations that are commensurate with network lifecycle risk management principles and efficient network investment.

Whilst this standard is primarily focused on network configuration at sub-transmission and zone substation levels, distribution network configuration and network design constraints are briefly outlined in this standard where they impact upstream equipment requirements. Detailed configuration arrangements and objectives for the distribution network are specified in:

- MDI0026 – location of isolation points on the high voltage distribution network
- MDI0028 – underground distribution network design and;
- MDI0031 – overhead distribution: design standards manual.

The principles, objectives and configurations in this standard will be utilised to develop area plans.

2 References

External Regulations
Electricity Supply Act 1995 (NSW)
Electricity Supply (Safety and Network Management) Regulation 2014
Work Health and Safety Act 2011
Work Health and Safety Regulation 2017

External Standards
ENA National Electricity Network Safety Code (Doc 01-2008)
Service and Installation Rules of NSW: November 2016
NSW Industrial Noise Policy: January 2000
National Electricity Rules Version 89: February 2017
Performance Licence Conditions Schedule 1, *Design Planning Criteria*, published on 1 December 2007.
AS 1824.1:1995 – Insulation Coordination – Definitions, Principles and Rules
AS 60076:2011 – Power Transformers
AS 62271.1:2012 – High-voltage switchgear and controlgear – Common specifications
AS 60038:2012 – Standard Voltages
AS 2067:2016 – Substations and high voltage installations exceeding 1kV a.c.
AS/NZS 4536:1999 (reconfirmed 2014) – Life cycle costing – an application guide

Company Policies and Procedures
Company Policy 2.0.5 – Risk Management
Company Policy (Network) 9.1.2 – Reliability Principles
Company Policy (Network) 9.1.4 – Network Power Quality
Company Policy (Network) 9.2.1 – Network Planning
Company Policy (Network) 9.2.2 – Network Protection
Company Policy (Network) 9.2.5 – Network Asset Design
Company Policy (Network) 9.2.9 – Electrical Network Telecommunications
Company Policy (Network) 9.7.1 – Network Construction
Company Policy (Network) 9.9.1 – Network Asset Maintenance
Division Procedure (Network) GNV 1105 – Review and reporting of zone and transmission substation thermal overload ratings
Electrical Network Safety Management System
Endeavour Energy Electrical Safety Rules

Company Standards
Mains Design Instruction MDI 0028 – Underground distribution network design
Mains Design Instruction MDI 0031 – Overhead distribution: Design standards manual
Mains Design Instruction MDI 0050 – Network Power Quality Limits and Levels

3 Definitions and Abbreviations

Abbreviation	Meaning
AIS	Air insulated switchgear
AFIC	Audio Frequency Injection Control
BSP	Bulk Supply Point
DNSP	Distribution Network Service Provider
GIS	Gas insulated switchgear
LDC	Line drop compensation
SFU	Static Frequency Unit (audio frequency signal generator for AFIC)
S-TS	Subtransmission substation
SWER	Single Wire Earth Return
TNSP	Transmission Network Service Provider (TransGrid in NSW)
ZS	Zone Substation

Term	Definition
Continuous thermal rating	The maximum current that can be allowed to flow indefinitely through that asset without the asset suffering damage or accelerated ageing.
cyclic thermal rating	The cyclic rating of an asset is defined as the maximum rating, based on actual or generic load and ambient temperature cycles, which can be sustained without unreasonable, accelerated ageing of the asset. Operating equipment to cyclic ratings must not result in a rate of thermal ageing greater than that of operation at the continuous rating (over a given defined period).
credible contingency	A credible contingency is a network operational event that has a reasonable likelihood of occurring, such as failure or sudden and unexpected removal from operational service of a network element. It is an event that has the potential to have a significant impact on the secure operation of the subtransmission system or may result in a loss of supply from the distribution system.
distribution substation	A substation with a primary voltage of 11 kV or 22 kV, and a secondary voltage of 430 V, which is part of Endeavour Energy's distribution network.
earth fault factor	The ratio of the highest rms phase to earth voltage on a healthy phase during an earth fault affecting one (1) or more phases, divided by the rms phase to earth voltage at that location in the absence of any such fault. The earth fault factors are calculated from phase-sequence impedance components of the system.
effectively earthed system	A system where an earth fault factor does not exceed 1.4.
fault rating	The capability of the equipment to carry or interrupt fault currents, which are specified as the rated short-time withstand current or short circuit making/breaking capacity of the equipment. [1]
Load area	A geographic area defined by Asset Strategy & Planning Branch for the purposes of analysing network needs and network configuration. This may logically be the load catchment areas of zone substations supplied from a transmission substation or a bulk supply point.
Level of Redundancy	The level of redundancy provided for the network in the event of failure of a critical network element. This can be N-1, N-2, or more, depending on the security and reliability of supply required on the system.
network configuration	The relationship between two (2) or more independent network elements that are connected or are connectable through in-situ network control elements.
network element	The individual components that connect together to constitute an operational electricity supply network. This normally includes but may not be limited to underground cables, subtransmission and distribution

[1] Precautions where neutral earthing impedance and 11/22kV auto transformers are utilised must be provided in the design of earth fault return paths, as incorrect design may expose the network to earth fault factors more than 1.7 p.u.

Term	Definition
	overhead lines, switchgear, busbars, transformers and any other items that are used for the distribution of electricity in the Endeavour Energy network.
normal network configuration	The network configuration where all network elements are normally available for service, and where the network is configured and operating in the state that it was designed to normally be in.
per unit impedance	The impedance of a network element or a combination of network elements expressed as a ratio as referred to the refernce impedance for a particular per unit system base. Unless otherwise noted, the per unit impedance referred to in this Standard is on a 100MVA base.
standard voltage levels	Standard voltages are used throughout Endeavour Energy's network. The standard phase to phase rms voltages are: • sub-transmission: 132kV, 66kV, 33kV • high voltage (HV) distribution: 22kV, 11kV, 12.7kV SWER • low voltage (LV) reticulation: 400V (230V phase to neutral)
Sub-transmission substation	A collection of interconnected network elements forming a substation with a primary voltage of 132kV and a secondary voltage of 66kV or 33kV, which is part of Endeavour Energy's subtransmission network and supplies the sub-transmission network. It is noted that due to organisational nomenclature legacy, these assets have been previously referred to as transmission substations and may appear so named in other documents and in corporate signage.
zone substation	A substation which is supplied from Endeavour Energy's sub-transmission network at a primary voltage of 132 kV, 66 kV or 33 kV, and has a secondary voltage that directly supplies the distribution network at 22 kV or 11kV.

4 General

The configuration of the Endeavour Energy network must meet the requirements of this standard and the various load area plans to achieve a safe, reliable, cost effective and logical network arrangement.

4.1 Load area plans and network configuration

For every defined load area of the network there will be a plan developed with a topological arrangement of the network that allows load to be easily transferred between network elements contained within the load area to facilitate efficient network operation. Plans are developed for each load area and contain the normal supply arrangement topology, network element ratings, the associated prescribed reliability requirements, and network contingency arrangements and operations of the network within the load area.

Each load area plan will utilise standard configurations as outlined in this standard. The principles, objectives and configurations in this standard will be utilised to develop area plans.

4.2 Network topology summary

Endeavour Energy's sub-transmission network is fed from TNSP (TransGrid) Bulk Supply Points (BSP) mostly at 132kV and in some locations at 66kV. Endeavour Energy generally takes supply via feeders from the BSP to feed to both sub-transmission substations (STS) and zone substations (ZS) depending on the area plan. Sub-transmission substations are utilised to reduce the voltage to 33kV or 66kV to be fed into multiple zone substations at large centres of load. Zone substations in Endeavour Energy's network have primary voltages of 132 kV, 66 kV or 33 kV and reduce the voltage to 22 kV or 11 kV for distribution within a load area. Distribution substations transform distribution voltages to 400V (3-phase) for reticulation and use in commercial, residential and industrial purposes. Variations to this arrangement exist in some situations.

132kV, 66kV and 33kV networks are normally supplied from grid sources that originate from a single Bulk Supply Point (BSP). Sub-transmission feeders that interconnect across two or more BSPs, should they exist are normally operated open and reserved as alternative backup source for securing supply during outages. Notwithstanding, the 132 kV, 66 kV and 33 kV networks are operated in a meshed arrangement wherever practicable, with the highest proportion of elements in service whilst meeting design fault levels, protection and main grid operational constraints and catering for credible network contingency events.

The 22 kV and 11 kV distribution network is operated and constructed as a radial system with an appropriate number of HV cross-zone or cross-feeder ties and LV backup. Where possible, The cross-zone and cross-feeder ties are to be diversified across busbars and zone substations to cater for planned and forced busbar outages.

Some areas of the network may have non-standard protection and control provisions to support meshed 11 kV and 22 kV networks in order to achieve supply security, reliability or power quality requirements while still meeting protection and thermal constraints.

4.3 Standardised configurations

Standardising substation configuration and equipment requirements allow efficient planning, design and construction, operation and management of network assets. Standardisation, including provisions around substation asset size, footprint, and asset weight (in the case of power transformers) also facilitates effective essential spares management for the asset base.

The various substation configurations outlined in Section 5 are required to be implemented as standard configurations for the Endeavour Energy network. The standard configurations have been designed to meet the network performance objectives required under the National Electricity Rules, our licence conditions, and performance requirements given in Section 0, using Endeavour Energy standard equipment detailed in Section 7. The configuration allows for adequate network capacity to secure peak load while catering for credible contingencies.

Standardised substation designs must accommodate provisions for the expected ultimate configuration and equipment installation requirements of the substation, as well as facilitating the staging and scheduling of future network developments.

Where practicable, considerations to secure adequate maintenance windows for major transmission elements during light load periods may require additional capacity including, for example, preferences for three smaller capacity network elements (such as transformers) in a standard design rather than two larger capacity elements.

5 Standard configuration

The conceptual configurations outlined in this section are the present range of standard arrangements to be used in the development of a new substation. These configurations have been reviewed for their efficiency in minimising the amount of equipment, and their efficacy in meeting the appropriate network security, reliability and performance standards outline in this document. They also reflect historical approaches to an extent, but this standard does not require that present range of configurations be retrospectively applied to existing substations.

A complete substation design will require the selection of transformers, primary configuration and secondary configuration. This will depend on the load being supplied, existing electrical infrastructure, load area plan and assessment of how to best meet the objectives of this standard.

5.1 Subtransmission feeder networks

Supply to substations is to be established in such a way as to ensure that there is adequate capacity, appropriate levels of supply security, and performance with the required level of supply reliability. The subtransmission network must be developed according to the load area plan to meet these requirements.

The specification of the incoming feeders, including the number of feeders supplying substations and their rated capacity is to be decided according to the size of the load, thermal conditions and the potential for thermal constraints, probabilistically determined supply security levels, whole-of-life asset costs, and any relevant geographical constraints. Credible contingencies must be considered in undertaking the probabilistic assessment of the optimum feeder arrangement when developing the plan. This includes giving consideration to potential supply impacts on adjacent substations and/or busbars.

Consideration may be required to be given to providing additional reliability and security beyond conventional “N-1” deterministic supply security standards, based on probabilistic assessments of the existing and/or proposed network. This may be achieved by operating the substransmission network as a network of interconnected rings, subject to operational and protection requirements being satisfied.

Tee connections to the substransmission network are permitted in certain circumstances where there is adequate protection and the impact on reliability and security of supply has been assessed.

5.2 Primary side of transmission and zone substations

The incoming feeder and busbar configurations are to be selected based upon the network requirements of the load area plan, the number of incoming feeders and the firm capacity of the substation. This is to be analysed and selected by the Asset Strategy & Planning Branch.

A single bus configuration is to be used as the standard option for the primary side of a substation.

There are additional supply security and reliability enhancements inherent in ring, breaker-and-a-half and double bus arrangements. The variation of performance outcomes provided by these schemes requires justification on a risk-assessed[2] basis, as the corresponding changes in expenditure on the equipment, land, building space, spares and protection schemes is considerable. Such schemes shall be limited to key network areas based on the load area plan, for instance where a key substation is the interface between two (2) major BSP's.

The number of feeders, transformers, circuit breakers, switches and busbar sections shown in the figures below are indicative only and must be calculated and designed on a site-specific basis.

5.2.1 Single bus

A single bus configuration will be used in the majority of cases. It facilitates a meshed subtransmission network with multiple elements in service and is fully expandable to suit a range of network requirements.

Faulted elements are isolated by circuit breakers. For outdoor switchyards, circuit breakers can be replaced with motorised disconnectors for disconnection of faulted elements depending on the subtranmission network mesh arrangement and where rated suitable to break the required duty of the circuit being disconnected, including for maintenance activities.

For indoor GIS, circuit breakers will be required for each element in the single bus arrangement.

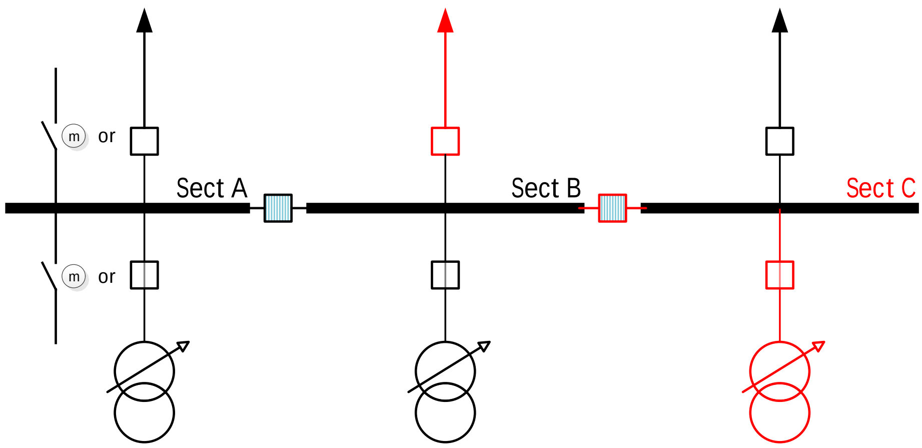


Figure 1: Standard Single Bus Primary Configuration

5.2.2 Ring bus

A ring bus provides greater switching flexibility, supply security and reliability performance than a single bus. This arrangement reduces the number of circuit breakers required but has additional motorised

[2] Note: may be any combination of increment or decremental cost / risk effect.

disconnectors. It must only be used where risk cost justified against the stated objectives of this standard. The ring bus is most effective for connecting two (2) or three (3) sets of pairs of network elements. Network elements are placed in alternate functions to achieve the best operational flexibility and reliability.

A ring bus arrangement can be staged from a single bus in the first instance, to allow development into a ring bus based on network need.

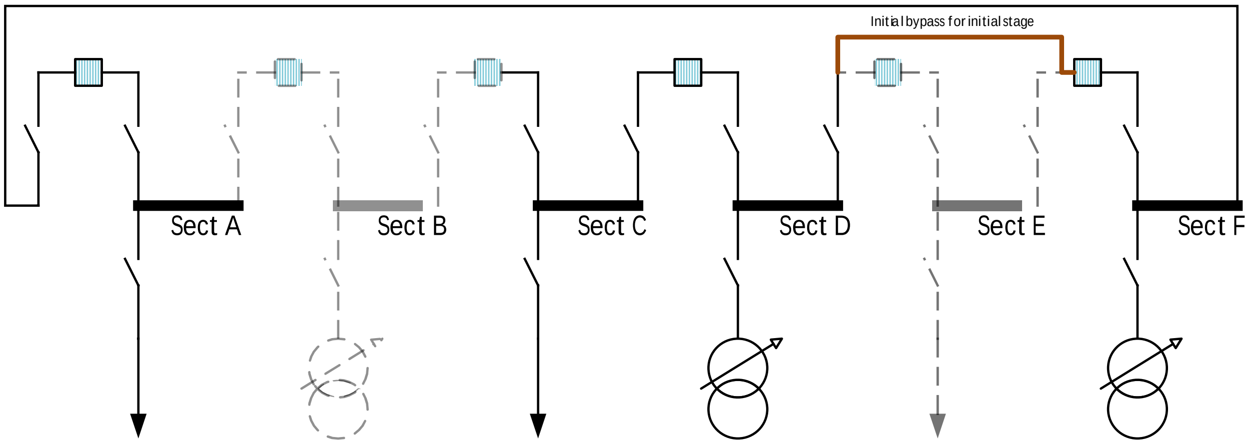


Figure 2: Ring Bus Primary Arrangement

5.2.3 Double bus

A double bus configuration provides greater switching flexibility and reliability than a single bus or a ring bus. It must only be used where risk cost justified against the stated objectives of this standard. This configuration will only be required at a few points in the network such as open points between BSPs which require switching flexibility and a large number of feeders. The design is expandable to accommodate extra feeders.

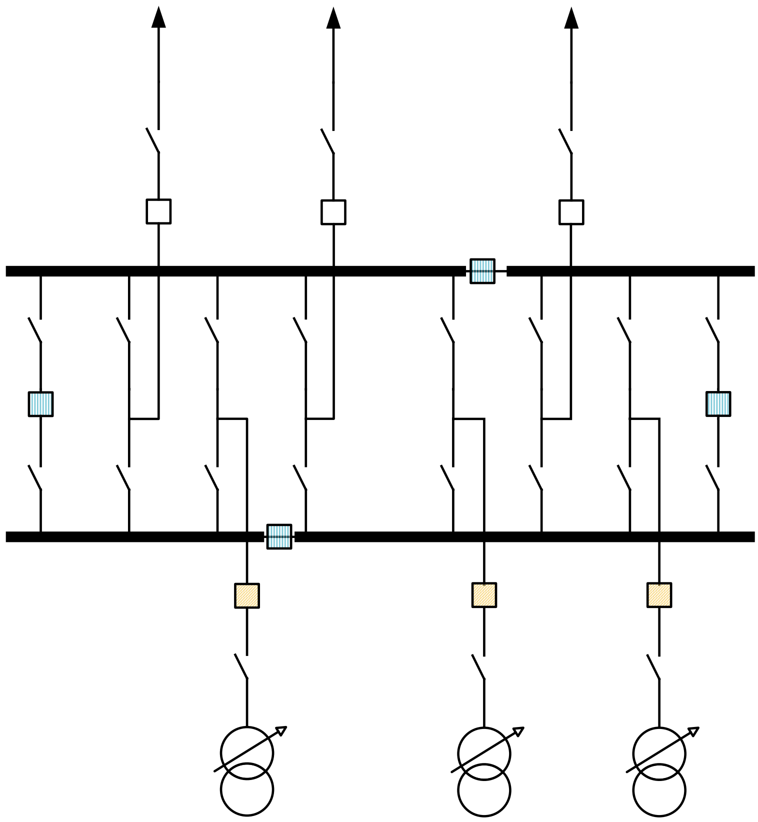


Figure 3: Double Bus Primary Configuration

5.2.4 Tail ended transformers

Tail ended configurations have the feeders directly connected to the transformer without any switchgear or busbars on the primary side of the substation. This will typically be at a remote site that does not require any switching flexibility. Consideration must be given to future network requirements and protection constraints. In particular, the risk of circuit breaker failure will be mitigated through the use of intertrip schemes, fault throwers or feeder distance protection provisions.

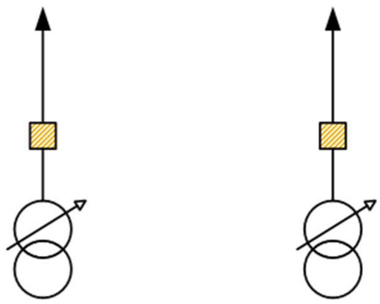


Figure 4: Tail-Ended Primary Arrangement

5.3 Zone substation secondary voltage configuration

Zone substation configurations must meet the objectives outlined in Section 8. The configurations and ratings in the following section must be treated as standard and any deviations must provide equal or better risk cost benefit based on reliability, security, stability, future requirements and the cost of implementation.

The number of feeder circuit breakers chosen for each configuration is based upon designed diversified feeder loadings determined from technical analysis as well as empirical evidence of actual feeder loadings. For 11 kV, provisions to allow double cabling will be made to maximise utilisation. At 22 kV, given the higher reliability impact of a feeder outage, double cabling is typically not utilised and will be reserved for feeders that are provided for backup supply only. Where an alternate back-up supply is required by major load customer, this can be provided by a connection to an alternate feeder that is otherwise supplying normal distribution load.

Transformers have either a designed or inherent cyclic overload rating. To maximise the output of the substation all equipment should be rated such that the substation can make use of the cyclic overload capability of the transformer. Load must be distributed to maximise the firm rating of the substation under contingency operation. Substation configurations have been designed to cater for this and will generally mean evenly sharing load between busbars. An exception to this is in the case of three transformer substations with single secondary bus, where the middle section will be of reduced load design such that no two adjacent sections exceed the temporary overload rating of any transformer (typically this being 130% of nameplate rating, to be verified on a case-by-case basis).

To manage fault levels all zone substation standard secondary configurations are to be designed to be operated in a split busbar arrangement: that is there will be no transformers operating in parallel under normal configuration. Parallel operation of transformers will only be allowed during switching operations or where the fault level can be shown to be within the limits specified in Section 8 whilst catering for future fault level growth from network changes and embedded generation. This is to be determined by Asset Strategy & Planning Branch on a per-substation basis and forms part of the area plan.

Table 1: Standard Network Configurations (Normal)

Secondary Voltage	Secondary Configuration	Primary Voltage		
		33kV	66kV	132kV
11kV	Single Bus Section	1 x 5MVA	1 x 5MVA	1 x 15MVA
			1 x 10MVA	
	Single Bus	2 x 15MVA	2 x 15MVA	
		2 x 25MVA	2 x 25MVA	2 x 35MVA
		3 x 25MVA	3 x 25MVA	3 x 35MVA
	Multiple Bus			2 x 45MVA
				3 x 45MVA
22kV	Single Bus			2 x 45MVA
				3 x 45MVA

Table 2: Configuration Circuit Breaker and Rating Detail

Ultimate Arrangement	1 x 5MVA	1 x 10MVA	1 x 15MVA	3 x 25MVA	3 x 35MVA	3 x 45MVA[a]	3 x 45MVA
Transformer Rating	5MVA	10MVA	15MVA	25MVA	35MVA	45MVA	45MVA
Secondary Voltage (kV)	11	11	11	11	11	11	22
Number of Transformers (ultimate)	1	1	1	3[b]	3[b]	3	3[b]
Firm rating design - MVA	*	*	*	50[b]	70[b]	90	90[b]
Overload allowance	130%	130%	130%	130%	130%	130%	130%
Diversified feeder load limit - A	220	220	220	220	220	220	220
Contingency feeder load limit - A	280	280	280	280	280	280	280
Emergency feeder load limit - A	350	350	350	350	350	350	350
Diversified feeder load - MVA	4.2	4.2	4.2	4.2	4.2	4.2	8.4
Transformer CB - # of	1	1	1	3	3	6	3
Transformer CB – rating – A	630	1000	1250	2000	2500	2000	1600
Busbar rating – A	630	1000	1250	2000	2500	2000	1600
Bus-section CB – number of	0	0	0	2	2	3	2
Bus-section CB rating – A	NA	NA	NA	2000	2500	2000	1600
Feeder CB - # of	2	3	4	12	17	22	11
Feeder CB rating - A	630	630	630	630	630	630	630
Feeder CB – Sect 1	2	3	4	4	6	4	5
Feeder CB – Sect 2	-	-	-	4	5	4	5
Feeder CB – Sect 3	-	-	-	4	6	4	5
Feeder CB – Sect 4	-	-	-	-	-	4	-
Feeder CB – Sect 5	-	-	-	-	-	4	-
Feeder CB – Sect 6	-	-	-	-	-	4	-

Notes: a - typically reserved for major CBD / large centre of load zone substations
b – utilisation of this configuration can be increased through use of cyclic ratings and provisions for network contingency through use of additional auxiliary busbar with load once full utilisation is met.

5.3.1 Single bus

A single bus configuration is the standard configuration for substations as per Table 3 based on firm capacity and nominal operating voltages. Faulted elements are isolated by circuit breakers. Note that the number of feeders, transformers, circuit breakers and busbar sections shown in Figure 7 are indicative only, with the actual number to be used based on the requirements given in Table 2.

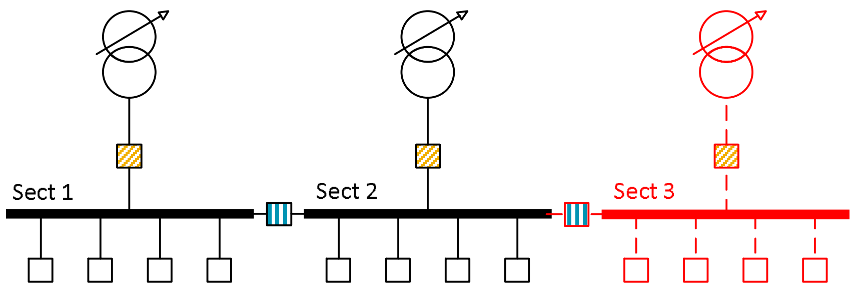


Figure 5: Single Bus Secondary Configuration

5.3.2 Multiple bus

A multiple bus configuration provides greater switching flexibility and reliability than a single bus. The design is expandable to accommodate an extra transformer and more distribution feeders. It is the standard configuration for substations as per Table 2 based on firm capacity and nominal operating voltages.

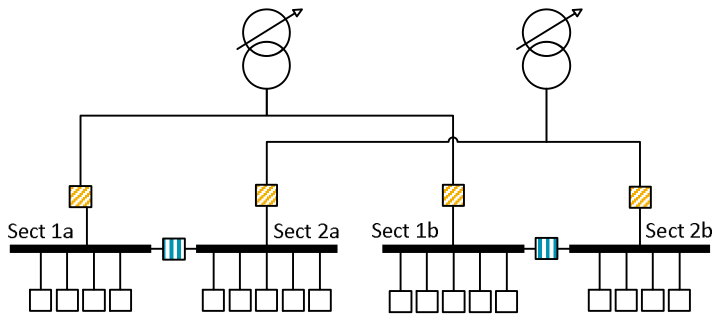


Figure 6: Multiple Bus Secondary Configuration

5.4 Subtransmission Substation Secondary Voltage Configuration

Subtransmission Substations are supplied from BSPs and supply multiple zone substations. The number of customers typically supplied from a subtransmission substation is therefore large and the reliability and security of supply prescribed for transmission substations is considerably important.

The number of feeders, transformers, circuit breakers, switches and busbar sections shown in the figures below are indicative only and must be calculated and designed for the specific site requirements.

As the maintenance and repair of indoor GIS may require prolonged busbar outages, its application in substransmission substations should therefore be only where necessary. Where required, additional feeder flexibility based upon cost-risk analysis may be required in these circumstances.

5.4.1 Single bus

A single bus configuration will be used in the majority of cases, where the firm capacity does not exceed 120MVA. This allows for a meshed sub-transmission network with multiple elements in service and is fully expandable to suit a range of network requirements. The meshed sub-transmission network is typically operated in a closed ring. In order to avoid the simultaneous failure of multiple feeders to the same zone substation due to a single busbar fault, feeders from the same mesh are be connected to different busbar sections where possible.

Faulted elements are to be isolated by circuit breakers. An additional bus-section circuit breaker to create a loop arrangement can be considered on a risk-cost-benefit-analysis depending on the sub-transmission network fed from the sub-transmission substation.

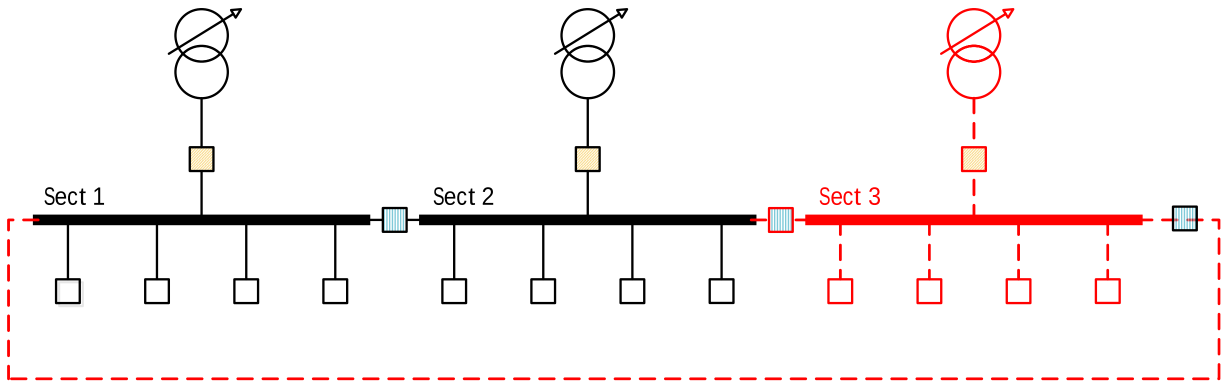


Figure 7: Single bus STS secondary configuration

5.4.2 Loop bus

A loop bus provides greater switching flexibility and reliability than a single bus and is the common arrangement where firm capacity exceeds 120MVA. This arrangement reduces the number of circuit breakers required but has extra motorised disconnectors. It must only be used where risk cost justified against the stated objectives of this standard.

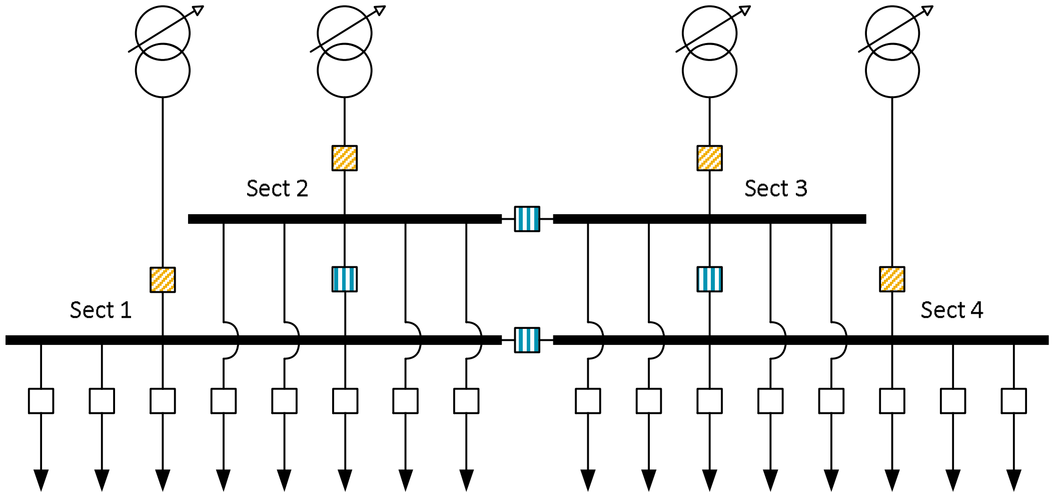


Figure 8: Loop bus STS secondary configuration

5.4.3 Double bus

A double bus configuration provides greater switching flexibility and reliability than a single bus or a loop bus as transformers or feeders can be transferred between busbars. The design is expandable to accommodate extra feeders. It must only be used where risk cost justified, on the basis of the significance of the load (magnitude and/or importance), high reliability and security requirements, and there is a minimum of three (3) transformers installed.

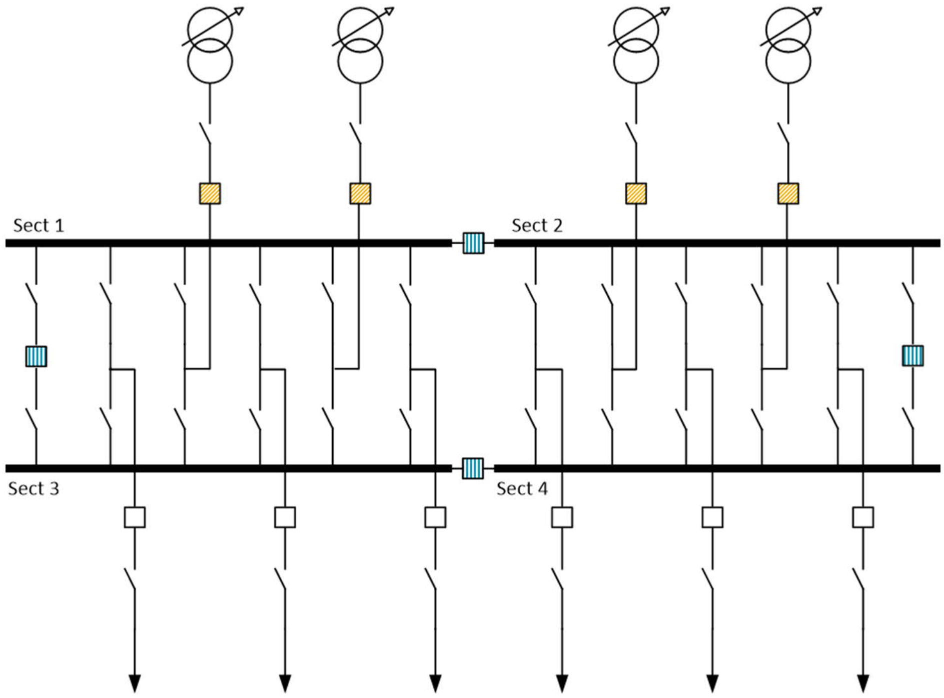


Figure 9: Double bus STS secondary configuration

6 Configuration and Design Principles

6.1 General principles

The following section provides the principles to be applied in the design and operation of the Endeavour Energy sub-transmission network. These principles include provisions for the whole-of-life cycle management of the assets from design and construction, through to maintenance, end-of life management and eventual disposal.

All designs must consider the human capacity, both physically and mentally, to construct, operate, test, maintain and dispose of the assets. All designs shall be undertaken considering the safety in design principles as stated in Company Policy 9.2.5 – Network Asset Design.

Substation configurations must be logical to all relevant workers. The design must be simple as reasonably practicable with regards to switching, connectivity, isolations and fault contingency operations.

6.1 Safety

All works, the configuration and equipment utilised in the network must be designed to comply with the Endeavour Energy Electrical Safety Rules. For high-voltage apparatus in particular this includes provision for safe isolation, testing, earthing and short-circuiting to allow safe work.

Additional safety provisions include, but are not limited to:

- having appropriate access for equipment installation, maintenance and replacement particularly with regards to live substation environment
- make suitable allowance for safe access to routine operating and visual monitoring locations
- make suitable allowance for safe work at heights with adequate space provided to allow ladders, scaffolding, elevated work platforms and the like to be utilised where required
- provide suitable access to emergency facilities such as eyewash, emergency shower and fire protection equipment in the event of an emergency
- prevent unauthorised access and have appropriate levels of security based on a site-based risk assessment
- minimise the risk of spreading or being affected by fire including fire protection of openings and penetrations to achieve risk minimisation

For operational purposes, a means of visual isolation or other approved method shall be provided for each network element by providing disconnectors on either side of circuit breakers to allow maintenance; otherwise the circuit breakers (CBs) shall be able to be withdrawn as appropriate if they are in an indoor switchboard. Visual indication can utilise technology such as built-in cameras or other direct methods to determine the state of disconnectors.

Indoor equipment must use interlocking facilities to prevent incorrect operation of circuit breakers, disconnectors and earth switches to allow safe operating conditions for operations and maintenance activities.

6.2 Configuration, Reliability and Supply Security

The standard busbar configurations for the network are to be based on a single sub-transmission voltage bus arrangement unless the principles described below afford a more economic lifecycle arrangement, either through significantly enhance reliability and supply security performance, or through improved network access. Should an enhance arrangement be required and/or justified loop bus, multiple bus, ring bus and double bus arrangements can be utilised.

When considering primary busbar arrangement, it should be noted that faults on busbars are rare. Consequently, the configuration selected to appropriately detect and clear faults whilst using the lowest total number of circuit breakers at the site. For instance, the use of a primary feeder circuit breaker and a bus-section circuit breaker to protect a transformer is considered adequate, and therefore dedicated transformer circuit breaker is generally not required unless there are specific protection and operating reasons to provide one.

This has been factored into the substation configurations outlined in the Section 5.

Noting that the substation configuration will impact the level of reliability and supply security, the configuration should be selected in accordance with the importance of the load being supplied (such as a CBD), the impacts of non-supply, customer and stakeholder requirements and expectations, and regulations.

Further, to achieve maximum reliability, substations will operate with as many elements in service as possible without exceeding maximum allowable fault levels and other network objectives.

The existing network was primarily designed in accordance with the Schedule 1 – Design Planning Criteria of the 2007 NSW Design Planning and Performance Licence Conditions, which was repealed in 2014. Notwithstanding, the principles of this Schedule are used to develop an initial assessment of the required network and substation configuration for new network developments, but any project proposal will require a robust probabilistic analysis of the load at risk, duration and other company risks in determining the final configuration.

The probabilistic analysis shall consider, but may not be limited to:

- Probability of failure of equipment or component (including gas chamber) of equipment (MTBF);
- Impact of failure including loss of load and damaged assets (where applicable);
- Maintainability of primary equipment at reasonable times throughout the year without jeopardising the reliability of supply to customers;
- Restoration possibilities and reasonable estimated of response and repair time (MTTR); and
- Detailed site consequence management including provisions of essential spares or mobile solutions suitable for quick response.

6.3 Environmental considerations

6.3.1 Community amenity

Where a new substation or development project involves the construction of a new building or development or the demolition or modification of an existing building or development, Endeavour Energy will self-determine the proposed development under the State Environmental Planning Policy (Infrastructure) 2007. Reference must be made to Environmental Management Standard EMS 0001 – Environmental impact assessment and environmental management plans. The requirements for substation buildings and developments requires appropriate functionality, meeting associated regulatory requirements and community expectations whilst maintaining the lowest practicable life-cycle cost.

6.3.2 Global warming potential

Endeavour Energy's preference is for the use of switchgear that does not contain SF6 gas given its management and global warming potential (GWP) where alternative cost-effective technologies are available. Cost-efficient offers of equipment containing SF6 will be considered for use in the network however weighting will be applied in the evaluation process to preference equipment with no or minimal SF6. A similar evaluation weighting will be applied to all gas insulated equipment regardless of gas used weighted by its GWP.

This impact must be considered in selecting if a substation will have indoor or outdoor switchgear.

6.3.3 Network losses

Network losses, in particular those for transformers, will be considered in whole-of-life cost. Capitalised losses will be based upon a rate in accordance with Company Policy 9.2.5.

6.4 Expandability

To minimise upfront costs, substations are often built in a staged approach to match the demand growth schedule, where expenditure is offset for as long as possible to minimise net present costs. With this in mind, designs are to provide for the possible future expansion of equipment, buildings and layout for additional capacity as the need arises, and for this to be achieved with the minimum amount of work or disruption to the network.

Buildings and switchgear are to have provisions for extension, and not necessarily be built for the ultimate arrangement unless clearly justified on a net present value basis.

6.5 Compatibility and spares management

All designs and equipment should be compatible with equipment that is currently available from manufacturers and widely used in the industry. Specifying equipment with features or ratings that are not currently manufactured or are a niche must be avoided unless approved by General Manager Asset Management.

The electrical and physical attributes of equipment will be standardised. The weight, size and footprint of equipment must be included in any standardisation where practicable to manage equipment failure risks. Spares must be kept, maintained and managed to allow for reasonable response times to failure of equipment.

6.6 Cost

Standard designs must provide a cost justified approach to supply electricity. Expenditure must be justified by safety, security, reliability, environmental and operational flexibility objectives.

The following objectives have been identified as key drivers for managing cost in the construction and maintenance of substations.

- Minimise substation footprint
- Minimise amount of equipment and future maintenance requirements
- Minimise variety of equipment
- Preference to outdoor transmission and sub-transmission equipment
- Optimised specifications of equipment

- Optimised selection of substation site
- Minimise power losses

A whole of life cost assessment must be completed taking into account losses, maintenance, future disruptions due to expansion, equipment and design costs. Life cycle costing guidance is provided in AS/NZS 4536 – Life cycle costing – an application guide.

6.7 Network connection coordination

The points where the Endeavour Energy network meets with other networks must be appropriately coordinated and managed by Asset Strategy & Planning Branch.

Any instance where the network creates a parallel path between two BSPs is to be managed in accordance with the TNSP's operating requirements. Configuration of supply, protection, control and contingency switching must all be coordinated with the TNSP to ensure stable operation of the main grid.

Similar consideration is to be be given for network connection points with other DNSPs, rail authorities and other major high voltage customers.

7 Primary Equipment Ratings and Requirements

7.1 Service (environmental) conditions

All equipment shall be suitable for use on Endeavour Energy's 3-phase 50Hz system. The service conditions are as per Company Policy 9.2.10 – Network Asset Ratings.

Table 3: Standard serice environmental operating conditions

Requirement		Result
Altitude		<1000m[3]
Outdoor equipment	Maximum ambient temperature	45 deg. C
	Minimum ambient temperature	-10 deg. C
Indoor equipment	Maximum ambient temperature	40 deg. C
	Minimum ambient temperature	-5 deg. C
Annual Keraunic days		30
Solar radiation - maximum		1.1 kW/m^2
Average index of mean relative humidity: 9:00am		95%
Seismic acceleration coefficient (maximum)		0.09
Pollution level		Level III / IV[4]
Ice coating		1mm
Maximum wind speed		34m/s
Condensation/precipitation		Yes
Electromagnetic disturbance		AS2650 cl.2.1i

7.2 Transformer operating parameters

Endeavour Energy's equipment will be designed to meet the conditions stated in this section. Transformers and equipment are to be suitable to operate under light load, heavy load and transformer core excitation worst case conditions defined in the tables below. The values in the tables below are not the worst case for each individual parameter, but rather the most strenuous conditions that could be considered to coincide. These are to be utilised to determine transformer impedance envelopes and tap-changer settings.

[3] Where altitude is higher than 1000m, then this shall be in the relevant Equipment Technical Specification.

[4] Level IV to be used in industrial areas and within 2km from the coastline otherwise Level III to be used.

Table 4: Transformer performance critical operating conditions for STS transformers

Parameter	Light Load	Heavy Load	Core Excitation
Voltage (pu)	1.1	0.925	
Current (pu)	0.25	1.3	1.3
Power Factor	0.95 lead	0.85 lag	0.86 lag
Frequency	50 Hz	50 Hz	47.5 Hz
Secondary Voltage (pu)	1.00	1.02	1.05
THD			7%[5]

Table 5: Transformer performance critical operating conditions for ZS transformers

Parameter	Light Load	Heavy Load	Core Excitation
Voltage (pu)	1.075	0.975	
Current (pu)	0.25	1.2	1.3
Power Factor	0.95 lead	0.9 lag	0.86 lag
Frequency	50 Hz	50 Hz	47.5 Hz
Secondary Voltage (pu)	1.00	1.02	1.05
THD			7%[6]

7.3 Standard transformer sizes and impedances

The standard transformers ratings for units to be employed in Endeavour Energy standard substation configurations are outlined in the table below.

Impedance curve characteristics are provided in Appendix B. Although these curves provide for a wide range of impedance across the tapping range, transformers purchased on the same contract will require

[5] 7% total harmonic content inclusive of a maximum 1.5% even harmonic content.

[6] 7% total harmonic content inclusive of a maximum 1.5% even harmonic content.

similar characteristics. Specifications for transformers shall consider the sites in which they will be installed and provide matching impedance curves where possible to achieve load sharing requirements.

7.3.1 ZS and STS standard transformers

Table 6: ZS and STS standard transformers

Voltage Ratio	Standard Tx size	Standard minimum impedance pu on 100MVA base.	Standard on Load Tapping Range	Standard Vector Group
33/11	5MVA	1.43 (7.15% on own base)	(+7 -14) x 1.5%	Dyn11yn11 / Dyn1yn1
33/11	15MVA	0.67 (10.05% on own base)	(+7 -14) x 1.5%	Dyn1 / Dyn11
33/11	25MVA	0.67 (16.75% on own base)	(+7 -14) x 1.5%	Dyn1 / Dyn11
33/11	35MVA	0.67 (23.45% on own base)	(+7 -14) x 1.5%	Dyn1 / Dyn11
66/11	15MVA	0.67 (10.05% on own base)	(+7 -14) x 1.5%	Dyn1 / Dyn11
66/11	25MVA	0.67 (16.75% on own base)	(+7 -14) x 1.5%	Dyn1 / Dyn11
66/11	35MVA	0.67 (23.45% on own base)	(+7 -14) x 1.5%	Dyn1 / Dyn11
132/11	35MVA	0.67 (23.45% on own base)	(+7 -14) x 1.5%	Dyn1 / Dyn11
132/11	45MVA	0.67 (30.15% on own base)	(+7 -15) x 1.5%	Dyn1 / Dyn11
132/22	45MVA	0.57 (25.65% on own base)	(+7 -14) x 1.5%	Dyn1 / Dyn11
132/33	60MVA	0.27 (16.20% on own base)	(+4 -16) x 1.25%	YNyn0d1
132/33	120MVA	0.17 (20.40% on own base)	(+4 -16) x 1.25%	YNyn0d1
132/66	60MVA	0.17 (10.20% on own base)	(+4 -16) x 1.25%	YNyn0d1
132/66	120MVA	0.17 (20.40% on own base)	(+4 -16) x 1.25%	YNyn0d1

7.3.2 Distribution standard transformers

Table 7: Distribution standard transformers

Voltage Ratio	Substation Type	Standard Tx size	Standard minimum impedance pu on 100MVA base	Standard Off Load Tapping Range	Standard Vector Group
11000/433 Or 22000/433	Poletop	25 kVA	132 (3.3% on own base)	(+2 -2) x 2.5%	Dyn11
		63 kVA	52.4 (3.3% on own base)	(+2 -2) x 2.5%	Dyn11
		100 kVA	40 (4.0% on own base)	(+2 -2) x 2.5%	Dyn11
		200 kVA	20 (4.0% on own base)	(+2 -2) x 2.5%	Dyn11
		315 kVA	12.7 (4.0% on own base)	(+2 -2) x 2.5%	Dyn11
		400 kVA	10 (4.0% on own base)	(+2 -2) x 2.5%	Dyn11
	Padmount	315 kVA	12.7 (4.0% on own base)	(+2 -2) x 2.5%	Dyn11
		500 kVA	8 (4.0% on own base)	(+2 -2) x 2.5%	Dyn11
		1000 kVA	5.0 (5.0% on own base)	(+2 -2) x 2.5%	Dyn11
		1500 kVA	4.2 (6.25% on own base)	(+2 -2) x 2.5%	Dyn11

7.4 Standard transformer requirements

The transformers shall conform to all relevant Australian and IEC Standards, in particular AS/IEC 60076 (all parts thereof). Appropriately sealed transformers may utilise natural ester oils or other synthetic oils to minimise fire risk, additionally dry-type transformers may be utilised in indoor environments.

The transformers in STS and ZS shall be able to regulate the voltage on-load within the tapping ranges specified above.

7.5 Continuous Current Ratings

Equipment continuous current ratings must be chosen from the standard sizes as shown above in the table below. Ratings are to be selected to allow for flexibility of operations in accordance with the network load area plan and coordination of ratings for substation loading. Continuous ratings must not limit the cyclic rating capability of the power transformers.

Full lifetime cost assessment of a site, taking into account expected ultimate loading levels is required to determine the ratings of equipment to be used at any substation.

Table 8: Standard operating current ratings for switchgear

<table>
<tr><th>Voltage</th><th>Equipment Type</th><th>630A</th><th>1250A</th><th>2000A</th><th>2500A</th><th>3150A</th></tr>
<tr><td rowspan="3">33kV</td><td>Feeder bay</td><td></td><td>✓</td><td></td><td></td><td></td></tr>
<tr><td>Transformer bay</td><td colspan="2">✓ ZS</td><td colspan="2">✓TS</td><td></td></tr>
<tr><td>Busbar section</td><td></td><td colspan="3">✓</td><td></td></tr>
<tr><td rowspan="3">66kV</td><td>Feeder bay</td><td></td><td colspan="4">✓</td></tr>
<tr><td>Transformer bay</td><td colspan="5">✓</td></tr>
<tr><td>Busbar section</td><td></td><td></td><td colspan="3">✓</td></tr>
<tr><td rowspan="3">132kV</td><td>Feeder bay</td><td></td><td></td><td colspan="3">✓</td></tr>
<tr><td>Transformer bay</td><td colspan="5">✓</td></tr>
<tr><td>Busbar section</td><td></td><td></td><td colspan="3">✓</td></tr>
</table>

7.6 Standard switchgear requirements

7.6.1 Indoor switchgear

Indoor primary switchgear must be metal-enclosed and designed so that Endeavour Energy’s normal service, inspection and maintenance operations can be undertaken in accordance with Endeavour Energy’s safe work requirements. The switchgear shall comply with the requirements of AS/IEC 62271 (all parts thereof). The switchgear used in Endeavour Energy’s network must have features that meet, but are not limited to the following requirements:

- visual determination of the energised or de-energised state of the main circuit and earth switch position;
- voltage indication for phasing;

- earthing of connected cables or other apparatus;
- locating of cable faults,
- voltage tests on connected cables or other apparatus and
- the elimination of dangerous electrostatic charges to allow works to be carried out safely.

Due to the space restrictions in substation buildings, switchboards with minimum space and minimal access constraints for cable termination are given preference.

Standardisation of equipment ratings for circuit breakers is required where possible to facilitate reduction of costs through minimisation of spares purchases and retention requirements.

Maintenance or failure of a component in the substation must not require the outage of adjacent functional units. For example, a gas chamber in GIS must not need an outage of adjacent functional chambers.

7.6.2 Outdoor switchgear

Outdoor switchgear is to be designed, manufactured and tested for outdoor service conditions. The switchgear shall comply with the requirements of AS IEC 62271 (all parts).

7.6.3 Instrument transformers

Current transformers for protection will be selected and specified in accordance with PDI 4002 and AS 60044.1.

Metering instrument transformers will be selected and specified in accordance with MET0002 and AS 60044.2.

8 Performance and Technical Standards

8.1 Power Quality

The network will be designed, maintained and operated to meet the following power quality objectives:

- achieve specific power quality levels which are inherent in the network design detailed in Section 8.1; and
- mitigate where reasonably practicable the adverse effects of specific load characteristics and system events on the power quality delivered to connected customers.

The power quality performance limits are detailed in MDI 0050 – Network Power Quality Limits and Levels. Equipment configurations and constraints detailed in this standard provide the required performance levels.

8.1.1 Voltage regulation and unbalance

The voltage at the secondary side of sub-transmission and zone substations will be regulated by on load tap changers whose tap positions and percentage tap step settings are in line with Table 8. Reactive power support may also be utilised to meet voltage regulation objectives. Load Drop Compensation (LDC) is applied where long and heavily loaded distribution feeders are installed at zone substations. Voltage regulators installed on distribution feeders provide supplementary control of voltage profile along HV distribution feeders where required.

The voltage at the secondary side of the distribution transformer will be regulated by regulating the voltage on the distribution feeder with provision for LDC. Distribution transformers will have offline tap changers whose positions and tap step settings are to be applied as given Table 7.

Sub-transmission feeder float voltage and regulation settings shall be set to maintain voltages within the range of the 90% to 110% normal voltage at Endeavour Energy's unregulated connection points, in accordance with the National Electricity Rules and to allow for the maximum distribution voltage regulation limits given in Table 9.

These unregulated voltage limits are to be considered in determining the impedance and tapping design of power transformers, In determining this worst-case primary voltage, load power factor and magnitude are not to be considered to coincide for credible system contingencies, in which case the parameters given in Section 7.2 are to apply.

Means of achieving the appropriate voltage level at the LV terminals of a distribution substation shall consider the voltage range on the busbar including provisions for designed LDC, and is to cater for foreseeable minimum load and maximum load network conditions.

Network voltage levels and voltage unbalance, including negative sequence voltage limits, must be maintained within the limits as defined in MDI0050 and the National Electricity Rules.

Table 9: Voltage regulation limits

Limits	Urban	Non-urban
HV (11/22kV) regulation	3.5%	6%
LV voltage drop (V)	10V	5V 10V within 5km of zone substation

The switching of large loads within Endeavour Energy's network may cause momentary voltage disturbances. The size of load switched at any one time shall be limited in order to minimise these disturbances.

8.1.2 Power Factor

Power factor requirements at bulk supply connection points are detailed in the Distribution Network Connection Agreement between the TNSP and Endeavour Energy and shall be met through the appropriate provision of capacitor banks or other reactive support plant throughout the network.

This will also be achieved by application of reactive plant at appropriate locations in the sub-transmission network and through active negotiations with customers for improvement of their power factor. Installations with supply voltage less than 50kV must have a power factor in the range of 0.9 lagging to unity, as defined in the NSW Service & Installation Rules. Locations with supply voltage greater than 50kV or up to 250kV must have a power factor in the range of 0.95 lagging to unity. This is in accordance with National Electricity Rules.

Reactive power flows (MVAr) will be controlled by reactive power support plant with automated control, coordinate with voltage regulation to achieve effective network operation within normal parameters.

8.1.3 Frequency and harmonics

The nominal operating frequency of the network is 50Hz. The control of the system frequency is the responsibility of the Australian Energy Market Operator (AEMO). The sustained operation of the system is kept within the range 47Hz – 52Hz through the scheduling of generators, generator governor settings and the use of under-frequency load shedding, the latter of which being generally deployed within the DNSPs network.

Under frequency load shedding is coordinated with AEMO.

Natural harmonics of integer multiples of 50Hz will occur on the network from a number of sources. Additionally, inter-harmonics (non-integer multiples) are becoming more prominent in modern electrical networks. Strategies that mitigate the effects of harmonics include the winding configuration of transformers, and natural damping of the network. Harmonic voltages and current on the network must meet requirements of MDI 0050 through coordination with customer loads and the use of harmonic filters where required.

Endeavour Energy uses remote load control technologies that inject audio frequency control signals of 283.3, 396, 750 and 1050Hz in various parts of its network in order to dispatch and control schedulable load. More onerous current distortion limits are required in these areas that use audio frequency signals to control loads in order to the risk of interference.

8.2 Insulation coordination

The selection of the dielectric strength of the insulation of equipment will be coordinated so that there is no unreasonable [7] failure of equipment due to lightning and impulse voltages. The short-time power frequency withstand and lightning impulse voltage levels are selected according to the highest nominal system voltage that will appear on the system. Switching surge characteristics are to be considered for

[7] Target failure rate of less than 1 in 1,000 per unit annum in accordance with IEC6007-2: Insulation coordination application guide.

highly capacitive circuits. The service environment and the arc clearing characteristics of the circuit , operation speed and type of protective devices must be assessed in the specification of switchgear for the coordination of insulation requirements with other equipment.

Insulation level standards for Endeavour Energy are provided in Section 8.3.

8.3 Short circuit fault levels

Short circuit current levels and energy must be managed so that equipment ratings, earthing risks and arc flash risk criteria are not exceeded. Maximum design fault levels as well as equipment minimum ratings are found in Table 10.

Table 10: insulation level and equipment short circuit rating

System nominal voltage (kV rms)		11	12.7 (SWER)	22	33	66	132
System highest voltage (kV rms value)		12	14	24	36	72.5	145
Rated short-duration (1 min) power frequency withstand voltage (kV rms)		28	50	50	70	140	275
Rated lightning impulse withstand voltage (kV peak)		75[8]/ 95	95	125/ 145[9]	170	325	650
Equipment Short circuit current (kA) for 1sec	**In supplying substation**	20		20	31.5	31.5	40[10]
	In network	16[11]	13.1	16[6]	26.2	24	31.5[5]
Maximum allowable design fault level (kA)		13.1	13.1	13.1			

Short circuit fault current levels for equipment are specified in terms of fault energy that the equipment can endure. This is typically expressed in the current (kA) and the time duration, including provisions for asymmetry of the current waveform due to fault and/or switching instant and network X/R ratio. For standardisation, this is determined based on equipment highest nominal voltage and location in the network.

Lower fault energy that is achievable with minimal operating restrictions will be utilised where possible. This has the benefit of extending service lifetime of equipment through reduced through fault current and reducing risks associated with arc fault energy and step and touch potentials under fault conditions.

[8] 75kV applies to distribution substation equipment protected by close surge arrestors or cable networks with low residual voltage (<34kV at 10kA 1.2/10us)

[9] 125kV applies to distribution substations, 145kV applies to zone substations.

[10] Cables operated at 132kV may be specified with fault duration of 0.5 seconds if approved in writing by the General Manager Asset Management or his nominee.

[11] 13.1kA (250MVA) is historical but modern objectives require 16kA

Notwithstanding these requirements, maximum fault levels may be exceeded for momentary periods during make-before-break changeover operations provided such operations can occur without supply interruption, network risks, are detrimental safety impacts.

8.4 Thermal capacity

The network is to be designed to operate within the thermal capability of primary plant under normal and foreseeable abnormal conditions. Substation equipment is to be rated to supply both the worst case maximum continuous current and short-term emergency current under credible contingency conditions. Cyclic ratings of equipment are to be used where the units have been assessed and proven capable by test, or in accordance with GNV 1105 – Review and Reporting of Zone and Subtransmission Substation Thermal Overload Ratings.

Thermal capacity of UG cables and overhead conductors must be calculated according to:

- MDI0011 – Underground distribution cables – continuous current ratings
- MDI0046 – Transmission underground cables – continuous current ratings
- MDI0042 – Overhead conductor ratings

Site selection must consider the potential availability of secondary voltage cable and line feeder routes to allow the full firm rating of the substation to be supplied from the substation. This may require the acquisition of suitable perimeter land, or the use of corner lots where possible.

Based on the cable ratings details provided in the Appendix, the number of secondary distribution (11kV or 22kV) feeder circuit breakers has been selected for a:

- Diversified target feeder load of 220A
- Normal operating contingency feeder load of 280A
- Emergency feeder load of 350A

Details on how to achieve the required ratings are detailed in the standards referenced in 8.4 and Appendix A.

8.5 Protection and Control Requirements

The network must be designed such that standard protection schemes are able to meet the requirements of Company Policy 9.2.2 – Network Protection, as well as an appropriate level of reliability and supply security. Protection elements will limit the damage to the network due to faults and prevent the remaining network and generators from becoming unstable whilst meeting critical clearance requirements of the National Electricity Rules.

8.5.1 Embedded generation

Embedded generation, such diesel generators in customers premises or industrial sites with large scale generation such as gas turbines, may be used in the Endeavour Energy network to support system voltage and capacity as required by network operating conditions, or in accordance with customer demand management and load curtailment agreements. Generators in these situations may be required to synchronise with Endeavour Energy's network and export real and reactive power as required and specified in the relevant connection agreement with the customer.

Embedded generators may also provide support functions to an islanded network during upstream outages for planned work to minimise customer interruptions and improve network reliability outcomes.

Alternatively, these customers may be supplied entirely by the generator, with the generator operating in an islanded mode. An upstream recloser may be used as an isolating point when islanding the generator. The recloser switch must be a ganged switch such that all three phases operate simultaneously for coupling or decoupling the islanded network.

The possibility of synchronising an islanded generator back into the network shall also be considered as such an arrangement has the potential to reduce outages to customers and also improve network reliability outcomes. Modern reclosers have functionality to latch synchronise and may be utilised for this purpose in coordination with the generator control scheme.

8.6 System Control and Data Acquisition (SCADA)

All substations are to be equipped with remote operation and data acquisition facilities, known as SCADA. All circuit breakers and transformer tap changers shall be controlled automatically or by the operators remotely through the SCADA network. Infrastructure must be provided with sufficient capacity, reliability and security to meet the telecommunications requirements for electrical network operational control and data needs as they may vary from time to time.

The changeover of elements from standby to in service on-load, dependant on the network configuration, must occur with a high certainty of success within the shortest period of time.

8.7 Schedulable and controllable loads

Various technologies are available to control schedulable loads, including time-switches, Audio Frequency Injection Control (AFIC), radio remote control, internet-based control and smart meters.

The predominant technologies currently deployed in Endeavour Energy's network for this purpose includes time-switch control and AFIC. In the future, schedulable load control is expected to be implemented using internet-based or radio remote control and smart meters.

The AFIC system injects audio-frequency current into the network at frequencies up to 1050Hz through a coupling cell connected to the 11 kV, 22 kV or 33 kV busbar. This may be either directly or indirectly through an auxiliary busbar, with the signals detected by control relays at consumers premises.

AFIC systems are presently implemented in accordance with the requirements of SDI 511.

9 Secondary and ancillary systems

9.1 Auxiliary and backup

Auxiliary switchgear and associated supplies are required to connect the AFIC signals to the load where applicable, to provide power to frequency injection systems, oil filtering, battery charger(s), pumps, fans, light and small power, as well as other AC control circuits and equipment. Typical auxiliary supply arrangements are shown in SDI 511.

9.1.1 Sub-transmission substations

Sub-transmission substations shall have duplicate low voltage power supplies that are supplied from power transformer tertiary windings through auxiliary transformers. Auxiliary transformers shall be connected directly to the power transformer tertiary windings rather than through auxiliary switchgear due to the high fault levels typically present at the tertiary winding and the unavailability of switchgear rated for these fault levels.

9.1.2 Zone substations

Zone substations shall have 400V/230V auxiliary distribution systems however 11kV or 22kV auxiliary switchgear shall only be used in exceptional circumstances as determined in SDI 511.

An auxiliary transformer shall be used to provide the primary supply to the auxiliary transformer distribution board. A secondary supply (backup) shall also be provided from a street supply through a changeover switch in accordance with SDI 511.

9.1.3 Switching station

Low voltage auxiliary power shall normally be supplied from the street supply (if available). If a street supply is used, an isolation transformer shall be provided. The neutral on the street side of the isolation transformer shall not be earthed to prevent the transference of hazardous voltages out of the substation.

Where street supplies are unavailable, switching stations shall have an auxiliary transformer connected to a high voltage feeder.

If an auxiliary transformer is required, the Protection Manager shall be consulted in regard to the primary winding configuration, impedance and special protection considerations.

The use of a second low voltage auxiliary supply at switching stations can be considered subject to the successful completion of a comprehensive assessment of cost and risk benefits, based on all possible operational configurations.

9.1.4 Low voltage (400V/230V) primary and backup supply

In sub-transmission substations, the primary supply is from one (1) auxiliary transformer, while the backup supply is from a second auxiliary transformer.

Zone substation primary supply shall be provided from one (1) auxiliary transformer, which is totally dedicated to all the substation functions. The backup supply shall be provided from a street supply, where available. If a street supply is not available, a second auxiliary transformer can be installed, and this shall be supplied from a different section of 11kV (or 22kV) busbar.

Whenever the primary or backup supply is compromised for periods longer than one (1) day, alternative supplies, such as portable generators, must be provided so that the N-1 capability of the 400V/230V auxiliary power supply system is not compromised. Provision shall be made for the connection of backup generators to the auxiliary switchboard to provide for these circumstances.

There shall be complete isolation (including isolation of neutrals) between primary and backup supplies so that the supply that is not in use can be maintained safely whilst the other supply is in use.

The ratings of auxiliary supplies applicable at the various substations shall be as set out based on the table below.

Table 11: Auxiliary transformer size requirements

AFIC	Zone/subtransmission substation capacity (MVA)	Auxiliary Tx size (kVA)	Standard interrupting rating of circuit breakers and residual current devices (kA)[12]	Rated short circuit duration (seconds)
Yes	≤ 50	200	10	0.5
	51 to 70	315	14	0.5
	≥ 70	500	18	0.5
No	All	315	14	0.5

9.1.5 DC systems

All new substations must have two 110V nominal station battery systems – one for each protection system. Each battery system must have a separate and dedicated charger system and must be fed via separate dedicated AC circuits supplied by different phases from the AC panel. The batteries and associated chargers, including all associated wiring and protection must be kept physically and electrically isolated so that potential problems with one system do not affect the other.

Substations require communications and SCADA systems and the associated 48V or 12V nominal battery systems. These systems may run of DC-DC convertors from the main station battery provided they meet the total capacity requirement as indicated in the table below.

[12] *AS 2184 - 1985 - Low voltage switchgear and control gear moulded case circuit breakers for rated voltages up to 600 V a.c. and 250 V d.c. clause 4.7.*

Table 12: Stations battery capacity requirement

Site	Battery system	Capacity requirement
Subtransmission substations and 132kV zone substations with firm rating > 20MVA	110V station battery (120V float)	300 Ah at 10hr rate 35A battery charger
	48V communication / SCADA battery (54V float)	200 Ah at 10hr rate 25A battery charger
	12V communication battery (where applicable)	40 Ah at 20hr rate
All other sites	110V station battery (120V float)	200 Ah at 10hr rate 25A battery charger
	48V communication / SCADA battery (54V float)	200 Ah at 10hr rate 25A battery charger
	12V communication battery (where applicable)	40 Ah at 20hr rate

9.2 Audio Frequency Injection Control (AFIC) requirements

Where an AFIC system is installed or is proposed to be installed, the following configuration arrangements shall apply, with the specific requirements are to be determined on a per substation basis by the Power Quality & Reliability Planning Manager.

Table 13: Network AFIC operating frequencies

Operating frequency	Geographical area	Network connection
1050 Hz	Western Sydney	11kV & 22kV
750 Hz	Illawarra	11kV
396 Hz	Kandos – Bylong	11kV
283 Hz	Shoalhaven	33kV

The audio frequency injection system signals are required to reach the limits of the network supplied by the substation. Details on capacity and power quality restrictions are provided in ETS0018-Frequency Injection Equipment.

Each substation's designated firm load rating shall be used to determine the appropriate size of the AFIC system components. For solid busbars each cell must be have a minimum capability of supplying firm capacity of the substation plus 10%. For split busbars with three (3) AFIC cells, each cell must have the capability to supply two thirds plus 10% of the firm capacity of the substation.

Table 14: Typical AFIC requirements for zone substations

No. of Transformers at ZS	Number of coupling cells and capacity	
	Solid busbar	Split busbar
3	2 x 110%	3 x 73%
2	2 x 110%	2 x 110%
1	1 x 110%	NA

9.3 Reactive Support

Capacitors are utilised in the network to manage power factor, reactive power flows and regulate voltage. The size and location of capacitor banks is determined by Asset Strategy & Planning through a study of the reactive load supplied by the substation. Point on wave (POW) switching technology may be required to switch capacitor banks in order to minimise voltage fluctuations on switching.

10 Authorities and Responsibilities

General Manager Customer & Assets has the authority and responsibility for:

- Approving this Standard, including any variations;
- Making all decisions concerning compliance in respect of this Standard; and
- Delegating any of these authorities and responsibilities to the Manager Asset Standards & Design.

Manager Asset Standards & Design has the authority and responsibility for:

- Reviewing this Standard and making recommendations to the General Manager Asset Management; and
- Making recommendations concerning compliance in respect of this Standard.

Substation Assets Manager has the authority and responsibility for:

- Clarifying all the technical aspects of this Standard with stakeholders; and
- Updating the relevant actions required and outlined in this Standard.

Manager Asset Strategy & Planning has the authority and responsibility for:

- Developing area plans for each load area using the standard configurations in this Standard; and
- Developing risk-based ranking of load areas and determining the configuration parameters from this Standard to be applied to the load area.

Appendix

Distribution (11kV & 22kV) Cable Rating Assumptions

Cable Details:

Situation	Size	Rating
Cable Rating (ducted)	11kV 3C 240mm^2 Al	320
	11kV 3C 240mm^2 Cu	420
	11kV 3C 300mm^2 Cu	475

Derating Factors:

Derating Factors	Soil Thermal Resistivity	1.2° Cm/W	1.0
	Depth	1.5m	0.96
	Duct Bank Size	4 Ducts	0.75
		6 Ducts	0.66
	Duct Bank Proximity	4 Ducts - 1m	0.85
		4 Ducts - 2m	0.91
		4 Ducts - 3m	0.93
		6 Ducts - 1m	0.83
		6 Ducts - 2m	0.91
		6 Ducts - 3m	0.93

240sqmm copper:

Scenario		Amps Per Cable (with derating factors)	Amps Per Cable (with offloading capability)
1	11kV 3C 240mm^2 Cu - 4 Ducts - 1m separation	257	193
2	11kV 3C 240mm^2 Cu - 4 Ducts - 2m separation	275	206

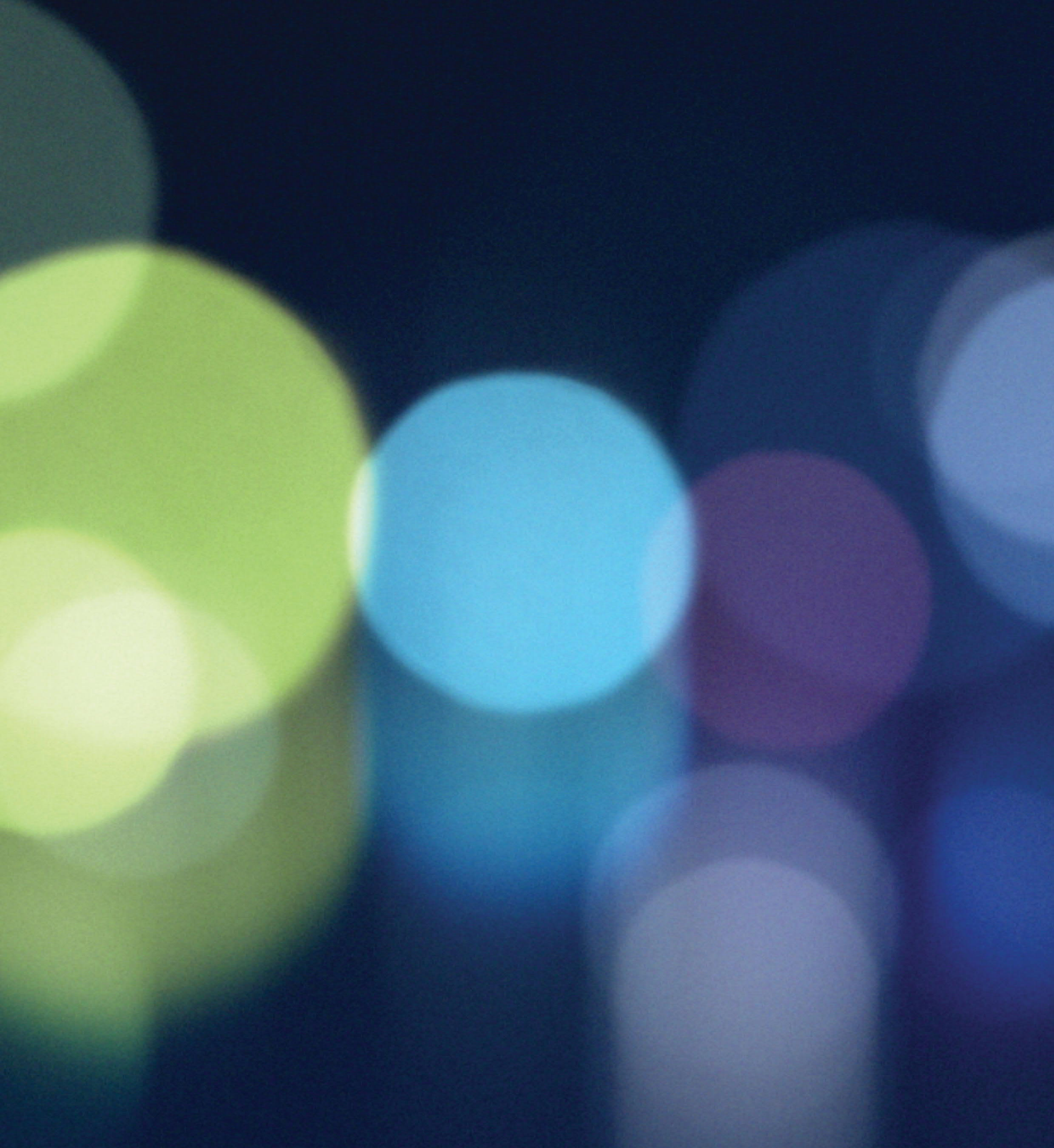
Scenario		Amps Per Cable (with derating factors)	Amps Per Cable (with offloading capability)
3	11kV 3C 240mm² Cu - 4 Ducts - 3m separation	281	211
4	11kV 3C 240mm² Cu - 6 Ducts - 1m separation	221	166
5	11kV 3C 240mm² Cu - 6 Ducts - 2m separation	242	182
6	11kV 3C 240mm² Cu - 6 Ducts - 3m separation	247	186

300sqmm copper:

Scenario		Amps Per Cable (with derating factors)	Amps Per Cable (with offloading capability)
7	11kV 3C 300mm² Cu - 4 Ducts - 1m separation	291	218
8	11kV 3C 300mm² Cu - 4 Ducts - 2m separation	311	233
9	11kV 3C 300mm² Cu - 4 Ducts - 3m separation	318	239
10	11kV 3C 300mm² Cu - 6 Ducts - 1m separation	250	187
11	11kV 3C 300mm² Cu - 6 Ducts - 2m separation	274	205
12	11kV 3C 300mm² Cu - 6 Ducts - 3m separation	280	210

In the network:

Scenario		Amps Per Cable (with derating factors)	Amps Per Cable (with offloading capability)
1	11kV 3C 240mm² Al - 4 Ducts	240	180
2	11kV 3C 240mm² Cu - 4 Ducts	315	236



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